National Grid EMR Electricity Capacity Report

1 June 2015

Report with results from work undertaken by National Grid for DECC in order to support the development of Capacity Market volume to procure for 2019/20.

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National Grid EMR Electricity Capacity Report

1. Executive Summary

This Electricity Capacity Report (ECR) summarises the modelling analysis undertaken by National Grid in its role as the Electricity Market Reform (EMR) Delivery Body to support the decision by the Government on the amount of capacity to procure through the Capacity Market auction for delivery in 2019/20.

1.1 Electricity Market Reform

Due to plant closures and the need to replace and upgrade the UK's electricity infrastructure, the UK electricity sector will require significant capital investment over the next decade. Electricity Market Reform (EMR), set out in the Energy Act 2013,[1] is designed to tackle the huge challenges facing the electricity sector ensuring security of supply and decarbonising of the power sector at an affordable cost to consumers. EMR has introduced innovative institutional and market arrangements to incentivise the estimated £100 billion of private sector investment needed from now to 2020 to replace the ageing electricity infrastructure with a more diverse and low-carbon energy mix.

The Government's objectives for EMR are to:

- Maintain a secure electricity supply
- Make progress towards our decarbonisation and renewables targets; and
- Ensure that consumers pay a fair price for low carbon electricity.

1.2 Requirement for Analysis

A key component of the Government's EMR package is the introduction of a Capacity Market from 2018/19 onwards to ensure the required security of supply is achieved in a cost effective manner.

To inform the level of capacity to procure for 2019/20 via the Capacity Market auction later this year, the Government requires National Grid to provide it with a recommendation based on the analysis of a number of scenarios and sensitivities that will ensure its policy objectives are achieved.

1.3 National Grid's Role

To inform the Government's decisions on the GB Capacity Market, National Grid, in its role as the EMR Delivery Body, will provide evidence and analysis to the Government. National Grid's electricity market knowledge and expertise will help to ensure that the analysis and evidence that inform Government's decisions are robust. National Grid already has the technical expertise, modelling, commercial and financial capabilities, and has expanded its resourcing in these areas to take on this task.

[1] http://www.legislation.gov.uk/ukpga/2013/32/contents/enacted/data.htm

1.4 Modelling Process

A key aim of the analysis to date has been to help the Government understand how different scenarios would impact on its objectives and ambitions, so that it can take informed decisions. The modelling approach adopted for the EMR Capacity Market analysis is described in detail in Chapter 3, including the data, assumptions and models utilised. The scenarios and sensitivities run through the model are detailed in Chapter 4. The scenarios and sensitivities investigated offer a range of likely demand and generation outcomes which are intended to meet the required security of supply as set out by Government's Reliability Standard.

The principal modelling tool National Grid has used is a fully integrated power market model, the Dynamic Dispatch Model (DDM). The model enables analysis of electricity dispatch from power generators and investment decisions in generating capacity to at least 2030. The model runs on sample days, including demand load curves for both business and non-business days. Investment decisions are based on projected revenue and cash flows allowing for policy impacts and changes in the generation mix and interconnection capacity. The full lifecycle of power generation plant is modelled through to decommissioning, and account is taken of the risk involved in investment decisions.

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

National Grid has also considered the recommendations included in the Panel of Technical Experts (PTE) report on the 2014 process and adjusted and improved this year's analysis appropriately to address all their concerns. In addition there has been a series of workshops with Department of Energy & Climate Change (DECC), PTE and Ofgem to enable them to scrutinise the modelling approach and assumptions utilised.

1.5 National Grid Analysis Delivery Timeline 2015

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

The work was carried out between February 2015 and May 2015 and builds on the analysis that was undertaken for the 2014 ECR. In addition to the analysis around the recommended capacity to procure this year's ECR will include analysis around the de-rating factors to be applied to interconnectors in the Capacity Market auction later in 2015.

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

- Project plan developed in January 2015

- Scope of work for CM capacity and interconnector de-rating factors (DRFs) signed off by DECC February 2015
- Modelling analysis February to May 2015
- Interconnector de-rating factor analysis February to May 2015
- National Grid's ECR to DECC before 1st June 2015
- Publication of ECR in line with DECC publishing auction parameters planned for late June.

1.6 Summary of Results and Key Conclusions

National Grid has modelled a range of procurement options based around different combinations of scenarios and sensitivities. The assumption is that the Future Energy Scenarios (FES) will cover uncertainty by incorporating ranges for annual and peak demand, Demand Side Response (DSR), interconnection and generation with the sensitivities covering uncertainty in station peak availabilities, weather, wind and peak demand forecast performance. In addition to the FES scenarios, a DECC Scenario has been included for information but hasn't been included in the LWR calculation to ensure the recommendation is fully independent by basing it on and around the FES scenarios.

Scenarios

- FES Gone Green (GG)
- FES Slow Progression (SP)
- FES No Progression (NP)
- FES Consumer Power (CP)

In deciding which scenarios to use as reference cases from which to run sensitivities, a number of factors were considered:

- There is no "central view" of the four FES scenarios.
- At least two should be run to reduce any potential bias associated with using only one.
- Ensure the scenarios chosen use a range of low carbon/renewable deployment (FES range is around 3GW of nameplate capacity in 2019/20) and that resulting Capacity Market qualifying capacities are not the highest or lowest of the four scenarios.
- Avoid using scenarios at the edge of the range as this will further extend the range beyond the range derived from applying the sensitivities to the central scenarios to avoid disproportionally affecting the outcome of the Least Worst Regret calculation.

The two scenarios that best meet these criteria were Slow Progression and Consumer Power. Therefore these two scenarios were chosen as reference cases for the purpose of applying sensitivities. They were combined with the full range of sensitivities and the other two FES scenarios to calculate the recommended capacity to procure.

While the FES scenarios vary many variables (see list of primary assumptions in Annex 8.1) the sensitivities vary only one variable at a time. Each of the sensitivities is considered credible as it is evidence based i.e. it has occurred in recent history or is to address statistical uncertainty caused by the small sample sizes used for some of the input variables.

Sensitivities

The agreed sensitivities to model cover weather, plant availability and demand:

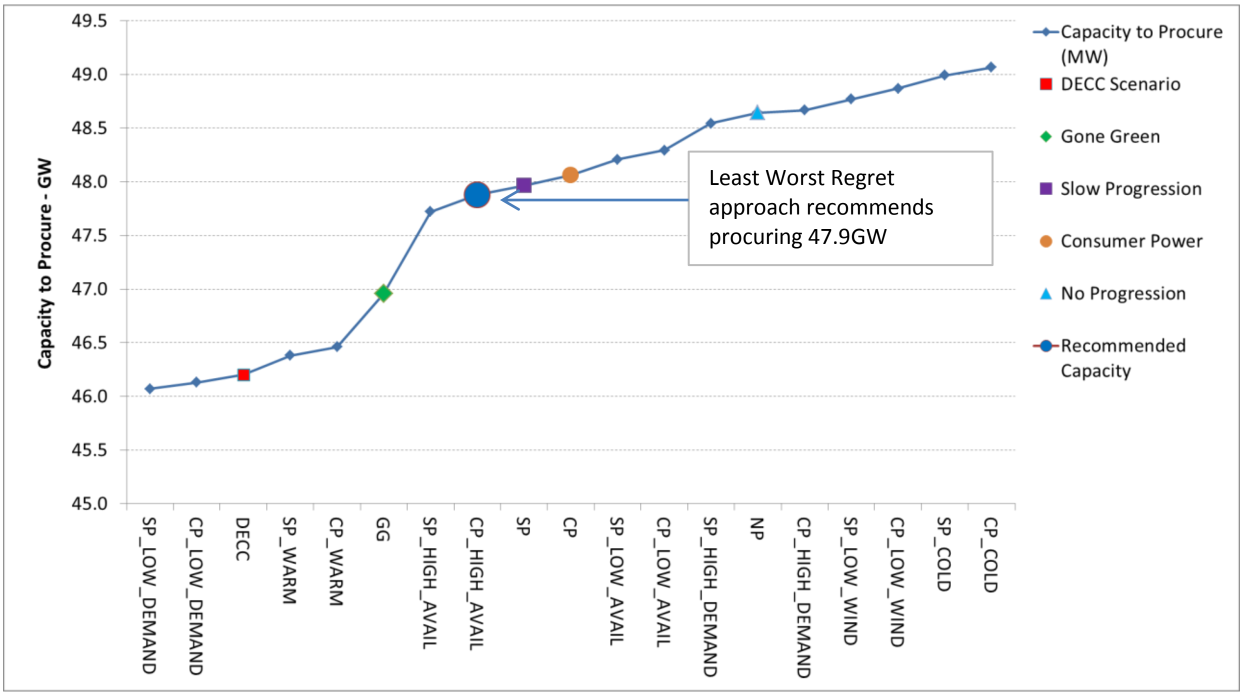
- Low Wind Output at times of cold weather (SP/CP LOW WIND)
- Weather Cold Winter (SP/CP COLD)
- Weather Warm Winter (SP/CP WARM)
- High Plant Availabilities (SP/CP HIGH AVAIL)
- Low Plant Availabilities (SP/CP LOW AVAIL)
- High Demand (SP/CP HIGH DEMAND)
- Low Demand (SP/CP LOW DEMAND)

Results

The scenarios and sensitivities are run through the model to give a Capacity Market eligible plant/interconnector total requirement. The range of potential procurement levels is shown in Figure 1 along with the result of the Least Worst Regret calculation which selects the Consumer Power High Availability at **47.9GW**.

A scenario or sensitivity is covered by the capacity procured if the Loss of Load Expectation (LOLE) is at or below the Government set Reliability Standard of 3 hours per year. If a scenario or sensitivity is not covered, and if one knew for certain that the scenario would occur in 2019/20, then the LOLE would be greater than 3 hours. This would increase the chances of controlled disconnection but may just result in mitigating actions (voltage reduction, max gen service and Emergency Assistance from interconnectors) being deployed more frequently/in higher volumes to avoid any controlled disconnections.

Figure 1: Capacity to procure options



Recommendation

The potential procurement levels shown in Figure 1 range from 46.1GW to 49.1GW highlighting the uncertainty in future outcomes. For all scenarios and sensitivities 5.5GW[2] of procured CM plant in 2018/19 has already been removed leaving the recommended capacity to procure for 2019/20, as calculated using the agreed LWR tool, of 47.9GW.

This year interconnectors have been modelled stochastically within the DDM rather than as scenarios and sensitivities. This derives an expected de-rated contribution from interconnectors at times of system stress. The capacity to procure takes account of non-CM plant (such as that in receipt of revenues via the CfD and RO), effectively subtracting this capacity from demand to be met. The remaining capacity requirement (including the de-rated contribution expected from interconnectors) forms the recommended capacity to procure. As the auction is for de-rated capacity and is technology neutral, this total capacity is offered for auction. Depending on bidding strategies, the composition of de-rated capacity that is successful may differ from that modelled without impacting security of supply.

The recommended procurement level is associated with the Consumer Power scenario which assumes a total level of DSR of 1.5GW in 2019/20; however, the FES range of DSR is from 1.3GW to 2.3GW. At this point in time, no information is available to National Grid on how much of this potential capacity would either participate in the year ahead (T-1) auction or opt out of the Capacity Market.

The recommended capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the four year ahead (T-4) capacity auction requirement, a number of adjustments to the recommended figure or range will need to be made:

- Government upon confirming auction parameters to National Grid prior to auction guidelines will determine how much capacity to hold back/take part in year ahead (T-1) auction; primarily for DSR but not restricted to DSR – wGW
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine DSR to opt out but remain operational - xGW
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine embedded generation to opt out but remain operational– yGW*
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine large scale generation to opt out but remain operational– zGW*
- Long Term STOR contracts (currently signed) need to be excluded (pre-qualification could change this) – 0.4GW**

Therefore, the recommended total capacity to procure through the 2019/20 T-4 auction will be:

[2] For more details on this procured capacity, see https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202014%20Final%20Auction%20Results%20Report.pdf

- 47.9GW-w-x-y-z-0.4GW

*National Grid's modelling assumes no generation or DSR opts out as no data is currently available to inform the modelling process but will hopefully become available through the pre-qualification process. Furthermore, as we expect DSR to be able to bid into the T-1 auction and can benefit from transitional arrangements in the meantime, this will mainly be a consideration for a T-1 auction.

** There is currently 390MW signed up under long term STOR contracts

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

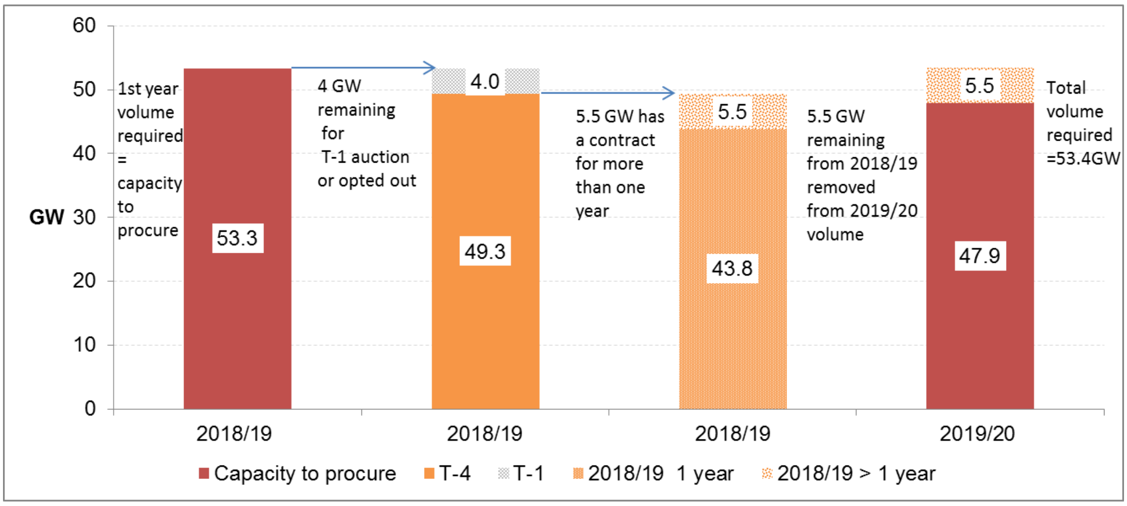
Comparison to 2018/19 recommended capacity requirement

Last year we recommended a volume of 53.3GW; however, this did not include any CM Agreements whereas, for 2019/20, 5.5GW of new and refurbished plant with a Capacity Market Agreement has been removed from the recommended capacity. On a comparable basis this gives a figure of 47.9+5.5=53.4GW i.e. in line with last year's headline figure as illustrated by Figure 2.

This time interconnectors can bid into the Capacity Market, whereas last year they were not – as such, the methodology accounted for it implicitly. A contribution of 0.8GW from continental Europe was assumed (net float if exports to Ireland are included). If the Secretary of State sets higher de-rating factors than those implied by last year's assumption, as recommended in this report (see Chapter 7), it may result in a lower requirement for domestic capacity in 2019/20 following the auction.

For example, in 2018/19, the requirement assumed 53.3 GW from domestic capacity and 0 GW (net) from interconnection. In 2019/20 the recommended requirement is for X GW from interconnection and 53.4 - X GW from domestic capacity (where X will be determined by the auction and the de-rating factor set by the Secretary of State).

Figure 2: Comparison to 2018/19 recommended capacity to procure



Potential range for interconnector de-rating factors

New for this year's ECR is the request for a range of de-rating factors (DRF) for each connected country to enable the Secretary of State to decide, with advice from the PTE, on appropriate DRF for each interconnector to enable their participation in the 2019/20 auction.

Subsequent to an initial review and discussions with DECC's PTE four alternative approaches were agreed to try and cover as many uncertainties as possible. This analysis included both commissioning consultants (Pöyry & Baringa) as well as National Grid's own background research. Each piece of work has its own strengths and weaknesses and provided a different view which when brought together will enable a realistic range to be identified. For more details on the results and analysis please refer to Chapter 7.

For all countries (except France), the Pöyry DRF sets the bottom of the range as this is the minimum bottom-stop DRF that will be allocated to each country. For France, the bottom of range is aligned to a higher value than Pöyry as the Pöyry DRF was largely based on a period before market coupling. The top of the range was set at or below the Baringa range.

- France 50-70%
- Netherlands 62-80%
- Belgium 58-70%
- SEM 2-10%

2. Introduction - Electricity Market Reform

2.1 Structure of Report

Chapter 2 gives an introduction to EMR and National Grid's involvement. Chapter 3 of the report aims to describe the modelling approach and the tools utilised. Chapter 4 of the report describes the individual scenarios and sensitivities modelled. Chapter 5 contains our approach to calculate capacity to procure and Chapter 6 contains the results from the scenarios modelled, along with conclusions. Finally Chapter 7 then covers the modelling and recommendation for the de-rating factors to apply to interconnectors in the 2019/20 T-4 auction.

2.2 EMR Summary

Due to plant closures and the need to replace and upgrade the UK's electricity infrastructure, the UK electricity sector will require significant capital investment over the next decade. Electricity Market Reform (EMR), set out in the Energy Act 2013, is designed to tackle the huge challenges facing the electricity sector ensuring security of supply and decarbonising of the power sector at an affordable cost to consumers. EMR has introduced innovative institutional and market arrangements to incentivise the estimated £100 billion of private sector investment needed from now to 2020 to replace the ageing electricity infrastructure with a more diverse and low-carbon energy mix.

The elements of EMR covered in National Grid's EMR work are:

- A mechanism to support investment in low-carbon generation: the Feed-in Tariffs with Contracts for Difference (CfD).
- A mechanism to support security of supply in the form of a Capacity Market.
- The institutional arrangements to support these reforms, for example the Capacity Market auctions.

This report concentrates on the second of these i.e. the Capacity Market.

2.3 National Grid (System Operator) Involvement

To inform the Government's decisions on CfDs and the Capacity Market, National Grid, as the System Operator, will provide evidence and analysis to the Government. National Grid's electricity market knowledge and expertise will help to ensure that the analysis and evidence that inform Government's decisions are robust. National Grid already has the technical expertise, modelling, commercial and financial capabilities and skills, and has expanded its resourcing in these areas to take on this task.

2.4 Capacity Market Overview

The Capacity Market ensures sufficient investment in the overall level of reliable capacity (both supply and demand side) needed to provide secure electricity supplies at levels up to and including peak demand. The Capacity Market works by giving all capacity providers a steady payment to ensure enough capacity is in place to meet demand. Capacity providers face penalties if they fail to deliver energy when needed.

The Capacity Market brings forward investment by allowing the market to competitively set a price for capacity. Capacity Market Agreements are offered to investors, in both existing and new capacity, four years ahead of the year capacity must be delivered, giving them certainty over part of the future revenues they will receive. There are also one year ahead CM Agreements offered to encourage the demand side to participate (although other forms of capacity will also be able to compete for one year ahead CM Agreements). The Capacity Market operates alongside the electricity market and the existing services National Grid contracts to ensure real time balancing of the system. The Capacity Market only applies to GB, not to Northern Ireland.

Interconnectors will be able to participate in the Capacity Market auctions for delivery from 2019/20 onwards. Previously estimates of the contribution from interconnectors, covering a range of flows, was incorporated in the analysis via scenarios and sensitivities. However, for 2019/20 interconnectors will be modelled in a similar way to generation i.e. stochastically thus covering the plausible range of flows in that way rather than through sensitivities.

2.5 Stakeholder Engagement

NGET 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 industry workshops, a summer seminar and one to one meetings with our stakeholders to ensure we are receiving up to date information and feedback for our scenarios. The FES are heavily influenced by stakeholder feedback to ensure the resulting scenarios are holistic, credible and plausible. Stakeholder feedback (pre-scenario development) is used to provide evidence of the credibility of these scenarios as part of the justification within our licence condition. The stakeholder feedback document[3] (published annually in January) contains details showing how stakeholder feedback directly influences the choice of scenarios and model inputs underpinning the scenarios. This document contains details of the questions that we ask our stakeholders and the range of their responses.

National Grid always looks to improve its stakeholder engagement to ensure it is meeting the changing needs of the wide range of customers and stakeholders. This is all built upon on National Grid's three themes of 'listen, discuss and act', a continual process that we follow when engaging with stakeholders. National Grid engages with stakeholders to explain its role in relation to EMR through the CM Implementation workshops throughout the year.

2.6 Generation Costs

DECC is currently in the process of updating their generation cost assumptions with an external researcher having been commissioned to collect data from industry. Unfortunately these updated costs won't be available in time to utilise in this analysis

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

so the generation cost assumptions are the same as those used in last year's ECR. This will have no material effect on the recommended volume of de-rated capacity to procure as that is non-generation specific so the relativity of costs won't affect the overall requirement.

3. The Modelling Approach

The process and modelling analysis has been undertaken by National Grid with ongoing discussions with DECC, Ofgem and DECC's EMR Panel of Technical Experts (PTE) during the development, modelling and result phases.

3.1 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 procure that will be required to meet the security of supply reliability standard of 3 Hours Loss of Load Expectation (LOLE)[4]?

In order to answer this question it was agreed, following consultation with DECC, that the Dynamic Dispatch Model (DDM)[5] was an appropriate modelling tool. This maintains consistency with the EMR CfD Strike Price analysis that National Grid undertook for the Delivery Plan. The DDM has the functionality to model the Capacity Market; the following sections describe this modelling in more detail. It should also be noted that when compared to National Grid's capacity assessment model, developed to support Ofgem's Capacity Assessment report[6], the DDM has been shown to produce the same results, given the same inputs.

The inputs to the model are in the form of scenarios and sensitivities from the FES[7], which cover a credible and broad range of possible futures. See Chapter 4 for details of the scenarios and sensitivities used in the modelling. A DECC Scenario has also been included in the analysis, which provides a point of comparison with DECC's own analysis and that contained in this report. These scenarios and sensitivities are built up of assumptions around:

- Peak demand – Prior to any demand side response
- Generation mix - Both transmission connected and embedded (within the distribution networks)
- Interconnector assumptions – Capacity assumptions (note that flows at peak are now modelled directly within DDM)

The modelling setup, detailed below, determines a capacity to procure 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 procure for those given circumstances and these are considered together to produce a recommended capacity to procure in the December 2015 Capacity Auction. This process is detailed in Chapter 5.

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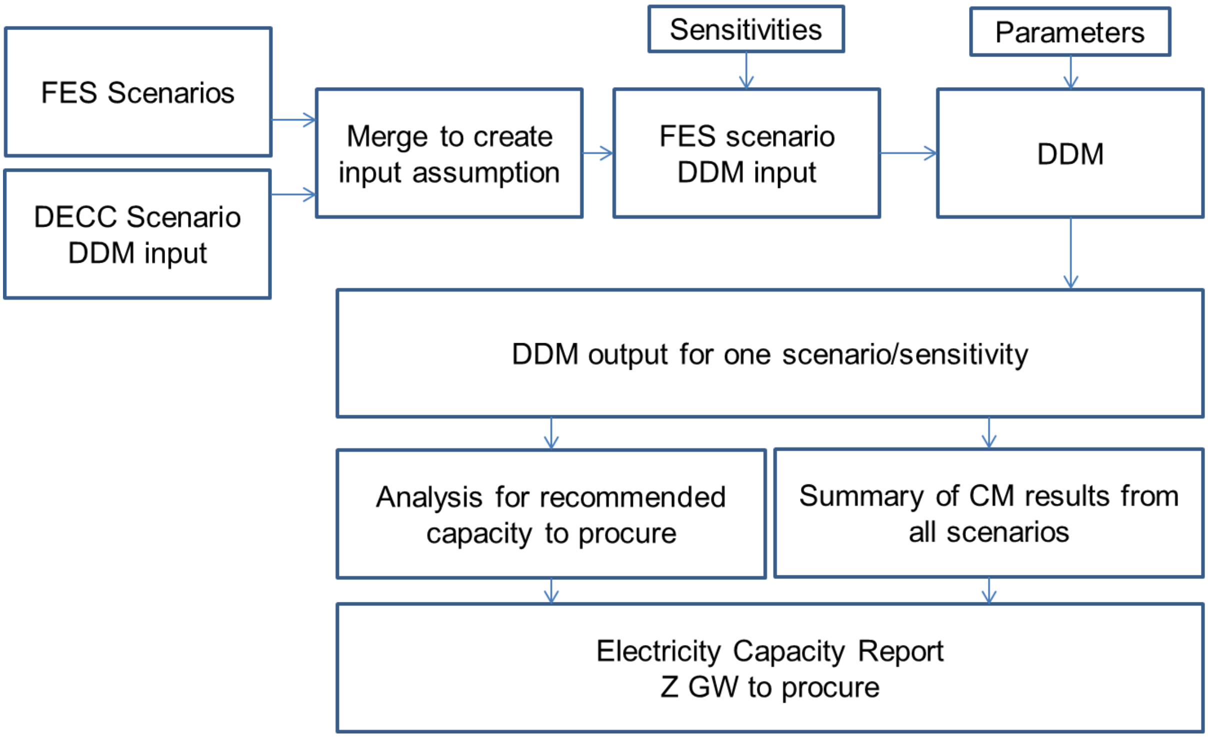
[4] *LOLE is the expected number of hours when demand is higher than available generation during the year.*

[5] DDM Release 4.0.24.2 was used for the 2019/20 analysis

[6] https://www.ofgem.gov.uk/ofgem-publications/88523/electricitycapacityassessment2014-fullreportfinalforpublication.pdf

[7] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

Figure 3: Concept diagram of modelling process



3.2 High level Assumptions

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

The starting point for the DDM input modelling assumptions was the assumptions which were used in the DECC Delivery Plan e.g. generation levelised costs (in 2012 prices).[8.] From this starting base, a number of the key assumptions were changed to align the modelling to the new FES scenarios and sensitivities. The key assumptions are those that materially affect the capacity to procure, these are:

- Demand Forecasts
  - Peak demand
  - Annual demand forecasts
- Generation Mix
  - Capacity eligible for the Capacity Market
  - Capacity outside the Capacity Market (including 5.5 GW procured for more than one year starting 2018/19)

For a summary of these key input assumptions see the Annex 8.

[8]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267614/Annex_D_-_National_Grid_EMR_Report.pdf

3.2.1 Demand Forecast

Each of the FES scenarios has its own annual demand projection; these are based on the underlying scenario narrative and together reflect a range of credible demand scenarios. The annual demands used in the sensitivities are identical to those of the scenarios on which they are based.

Each of the FES scenarios has its own peak demand projection; again, these are based on the underlying scenario narrative and together reflect a range of credible demand scenarios. The definition of peak demand used in the modelling is Unrestricted GB National Demand[9] plus demand supplied by embedded 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[10] (ACS) peak demand and is consistently applied within the sensitivities based on the Consumer Power and Slow Progression scenarios. The only adjustments to ACS peak demand are within the high and low demand sensitivities and the sensitivities around warm and cold winter weather. All forms of demand side response greater than 2 MW are eligible for the Capacity Market. This can include demand side response through the use of an aggregation service. Note that this includes demand side response at times of Triad charging periods. Therefore unrestricted peak demand is modelled i.e. no demand side response or triad avoidance has been subtracted.

See Annex 8.2.1 for details on the demand assumptions used in the FES scenarios and section 4.4.8 for more details on demand side response. The following table shows the peak demands (unrestricted end consumer demand plus losses but excluding exports and station demand) in winter 2019/20. There is only 1.4 GW difference between the FES scenarios, but the sensitivities increase the peak demand range to 2.9 GW from 58.3 GW to 61.2 GW.

Table 1: Peak Demand by Scenarios

Scenario	Peak Demand - GW
Gone Green	59.3
Slow Progression	60.3
No Progression	60.5
Consumer Power	60.7

3.2.2 Generation Mix

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

[9] National demand is defined in the Grid Code Glossary and Definitions http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/The-Grid-code/

[10] 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.

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

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

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

Any generation capacity that is under a total capacity of 2 MW is assumed to be not eligible for the Capacity Market in this modelling. The unsupported generation capacity that is under 2 MW has been estimated by National Grid to range from 0.6GW to 1GW by 2019/20 depending on the FES scenario. Note that this figure does not include small scale renewable technologies, as these are assumed to receive FiT support and are thus not eligible for entry into the Capacity Market.

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

Any capacity that receives a Capacity Market Agreement for longer than one year, which is either new plant or plant undergoing significant upgrades, will not be eligible for the subsequent auctions while it is under the existing CM Agreements. For the first auction, no capacity had an existing CM Agreement, but in subsequent auctions there may be a level of capacity that is under agreement. In the 2018/19 auction de-rated capacity of 5.5 GW received CM Agreements for more than one year. This procured plant is accounted for in the modelling so it will not be procured again.

The modelling focuses on estimating the total eligible capacity to procure to hit the 3 hours LOLE Reliability Standard as the precise mix of generation technologies will be decided by the capacity auction. A breakdown of installed “name plate” capacity for each FES scenario is shown below. It is split by eligibility for the Capacity Market in 2015/16 and what capacity is projected in each scenario outside of the Capacity Market for the first delivery year of 2019/20:

Table 2: Installed name plate capacity split by scenario[11]

	Outside of Capacity Market (GW)	Capacity Market Eligible (GW)
Gone Green 2015/16	17.5	65.9
Gone Green 2019/20	27.1	Model to determine
Slow Progression 2015/16	17.6	65.9
Slow Progression 2019/20	25.8	Model to determine
No Progression 2015/16	17.3	66.8
No Progression 2019/20	24.0	Model to determine
Consumer Power 2015/16	17.8	65.9
Consumer Power 2019/20	26.9	Model to determine

In the model inputs, the capacity outside of the Capacity Market is fixed to the level assumed in each scenario. The plant eligible to enter into the Capacity Market is initially set to today's view (including plant under construction), but the model will determine the precise capacity that is to be procured.

3.2.3 Interconnector Assumptions

As part of the UK's discussion with the European Commission on State Aid approval for the Capacity Market there was a commitment to include interconnectors from the 2019/20 auction onwards. This has therefore resulted in a new approach to modelling interconnectors where instead of estimating potential flows via scenarios and sensitivities these will now be determined by stochastic modelling in a similar way to generation technologies i.e. based around a set of flow distributions obtained from Baringa's pan European model.

In addition to this modelling work National Grid will provide a recommendation on the potential range of de-rating factors to apply for each connected country participating in the CM auction. See Chapter 7 for more detail around this process and the recommended de-rating factors.

3.2.4 Station Availabilities

Conventional generation capacity is not assumed to be available to generate 100% of the time, due to break downs and maintenance cycles. In order to determine what availability to assume for each generation type, National Grid considers what has been delivered historically, based on the average on high demand days over the last seven winter periods[12]. This approach has been used by National Grid in its entire medium to long term modelling, as well as being used for the EMR Delivery Plan and Ofgem's Capacity Assessment. This methodology is described in detail in Annex 7.2 of last year's ECR.[13]

[11] Note solar PV capacity is excluded as it does not contribute to capacity at system peak
Table 2 differs from table 7 in 2 ways: Table 2 shows nameplate capacity, Table 7 de-rated, in Table 2 the capacity purchased for more than one year starting 2018/19 is included in the CM eligible column but in Table 7 it is included in the outside CM column.

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

[13] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=34154

Table 3 shows the station availabilities based on the last 7 winters (2008/09 – 2014/15) for each type of generation. The mid availability is defined as the mean of each of the last 7 winter's availability values. The low and high values are defined as this mean plus/minus one standard deviation (of the 7 estimates).

Table 3: Low, Mid and High Availabilities

Generation Type	Low	Mid	High
CCGT	85%	87%	89%
OCGT	92%	95%	97%
Coal	87%	88%	89%
Nuclear	76%	82%	89%
Hydro	79%	85%	91%
Oil	76%	85%	93%
Pumped Storage	95%	97%	98%

Previous comments[14] from the DECC PTE stated that the availability of CCGT plant was low when compared to other markets with similar support mechanisms and recommended that National Grid undertake analysis to benchmark CCGT and other technology availabilities from around the world.

Subsequently, National Grid commissioned ARUP, in 2014, to produce a report on the availability of plant, particularly CCGTs, in markets that incentivise availability. For the main generation types CCGT, OCGT, coal and nuclear, ARUP provided an availability assumption. The following table shows the two views of availabilities

Table 4: Availability comparison

Generation Type	National Grid	ARUP
CCGT	87%	87% -93%
OCGT	95%	94%
Coal	88%	87%
Nuclear (Existing)	82%	77%

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

Table 5: Availabilities used

Generation Type	Availability %
CCGT Pre 2018/19	87%
CCGT 2018/19	88%
CCGT 2019/20	89%
CCGT Post 2019/20	90%
OCGT	95%
Coal	88%
Nuclear (Existing)	82%

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

Given the current plant economics, age and mode of operation it is not surprising that GB CCGT availabilities are at the lower end of the international range. The increasing CCGT availability reflects the introduction of the Capacity Market in 2018/19 and a three year maintenance cycle for the CCGT fleet to improve its availability once spark spreads rise. The nuclear availability from ARUP was considered to be at the low end of the range. National Grid has gathered information from Grid Code obligations and stakeholder feedback, not available to ARUP, to inform the final discussion on nuclear availability.

The 90th percentile of demand has been used for CCGTs rather than the 50th percentile since in recent years CCGT availabilities have been lower than expected (due to low spark spreads). This removes most of the commercial and planned outages and gives a figure of 87% (rather than 83% based on the 50th percentile of demand). By 2017/18, it is expected that spark spreads will be at a level to assume availabilities start to rise and reach the internationally benchmarked level of around 90% by 2020/21. The 50th percentile of demand was used for all other types of generation because there was no significant increase in the availabilities when using the 90th percentile.

Some views have been expressed that the CCGT availability is still too low and still includes commercial and planned outages. However, the assumptions behind station availabilities need to be evidence-based and if stations are taking planned outages at high demand periods then this needs to be reflected in the availability value until we have evidence otherwise. Failing to include this behaviour means that the availability values will be artificially inflated above the international standards.

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

Renewable plants run whenever they are able to, so the availability is not significant. When considering these plants, National Grid looks to their expected contribution to security of supply. For wind, this is achieved by considering a history of wind speeds observed across GB 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 wind generation and contribute the same to security of supply. Its assumptions are driven by the installed wind capacity as well as demand and generation mix assumptions, with consideration also given to tightness of the system as a whole. It should be noted that the EFC is not an assumption of wind load factor at peak times and consequently should not be considered as such.

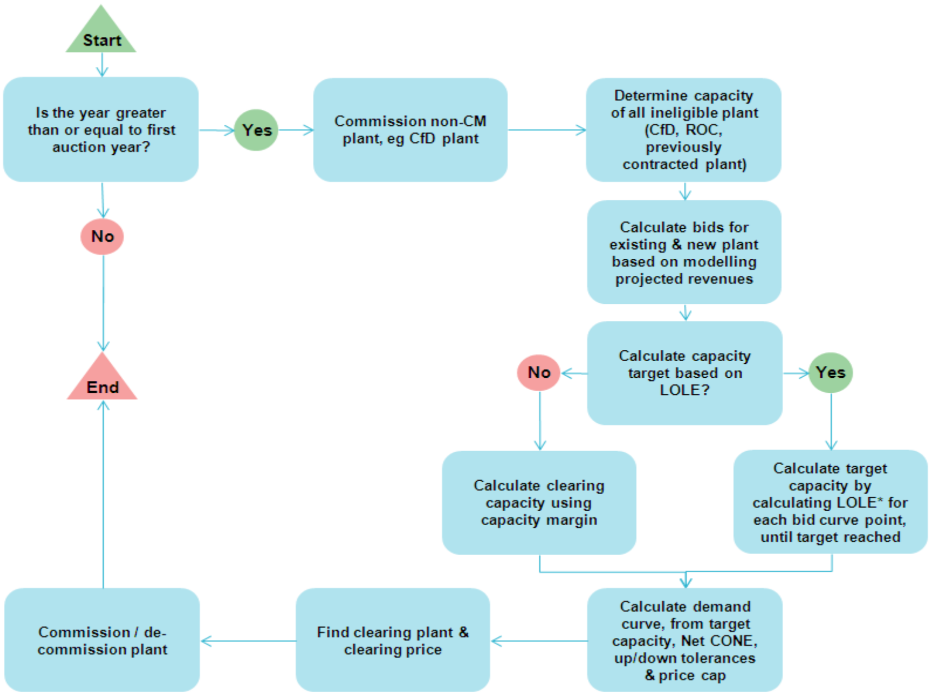
In the DDM, we have modelled the contribution of interconnectors at peak times by assigning a probabilistic distribution to each interconnector, defining the probability of each import / export level for a given level of net system margin. These distributions were derived from the analysis carried out by Baringa (see Chapter 7). The DDM calculated an EFC for interconnection which was used as an estimate of the aggregate interconnector de-rated capacity. Note that the modelled de-rating factor for interconnection has no impact on the total de-rated capacity (including interconnection), required to meet the Reliability Standard. In the auction interconnection capacity will compete with other types of new/existing eligible capacity to meet the capacity requirement.

Given that the recommended capacity to procure is a de-rated value the assumptions around availability of both conventional and renewable capacity have limited impact on the recommendation (around 0.2GW). Broadly the same level of de-rated capacity is required to hit the 3 hours LOLE; however, the name-plate capacity required to achieve that level of de-rated capacity will be different. See Table 5 in Chapter 6 for the details for the details of how de-rated capacity changes with changes in availability assumptions.

3.3 Using the DDM to Model the Capacity Market

As outlined in section 3.1, the decision was to use the DDM to model the capacity to procure. The DDM is able to model investment decisions for renewable and low carbon technology, so it was used by DECC and National Grid for the analysis to calculate the CfD strike prices for the EMR Delivery Plan. The DDM also has the functionality to model the Capacity Market and so it is used in this analysis.

Figure 4: Functionality of Capacity Market Modelling



Source: Lane Clark and Peacock[15]

The modelling of the Capacity Market is achieved by targeting a LOLE of 3 hours. For the auction year starting in 2015 for delivery in winter 2019/20, the model assesses conditions four years ahead and determines the volume of capacity that will be present. This capacity is then stochastically modelled around the conventional generation's availability and the EFC contribution from wind capacity and

[15] Lane Clark and Peacock developed the DDM model

interconnection. Given the assumed peak demand (and distribution around it), the LOLE is then calculated.

If this LOLE is not equal to 3 hours then the model will either reduce the amount of capacity by retiring existing plant or commissioning new capacity.

3.4 DDM Outputs Used in the ECR

For the purpose of the ECR, the key outputs utilised from the DDM for each year modelled from 2019/20 to 2029/30 are the aggregate capacity values, specifically:

A. Total de-rated capacity required to hit 3 hours LOLE
B. De-rated capacity to procure in the Capacity Market auction
C. De-rated capacity expected to be delivered outside the Capacity Market auction
D. Total nameplate capacity split by CM and non-CM eligible technologies.

Note that A = B + C. Further details on the modelling and aggregate capacities can be found in Annex 8.3.

In addition to the aggregate capacity values, for the purpose of calculating the recommended capacity to procure in 2019/20, the ECR also utilises the expected energy unserved (EEU) values for potential de-rated capacity procurement levels in 2019/20 output by the DDM (see sections 5.2 and 6.1.3 for more details).

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

3.5 PTE Recommendations

In the PTE's "Final Report on National Grid's Electricity Capacity Report[16]" they identified a number of key points and issues which have been addressed as follows as part of this year's process:

1. Use of FES scenarios as the basis for the analysis was strongly endorsed by the PTE

   – For the 2015 ECR we have continued to base our analysis around the FES scenarios.

2. Treatment of interconnector flows at peak. Last year the PTE expressed concerns over the level of imports assumed at peak being too conservative and thus resulting in a higher capacity to procure figure. However, the figure assumed was consistent with previously published National Grid views e.g. in the FES and Winter Outlook documents and also feedback from industry.

   – For the 2015 ECR we have developed a new approach that models interconnectors stochastically within DDM based on distributions for each

16 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324976/EMR_Panel_s_Final_Report_on_National_Grid_s_ECR.pdf

interconnector from Baringa's pan-European market model and the 2015 FES interconnector capacities. This derives an expected de-rated contribution from interconnectors at times of system stress. The capacity to procure takes account of non CM plant (such as CfD and RO), effectively substituting this capacity from demand to be met. The remaining capacity requirement (including the de-rated contribution expected from interconnectors) forms the recommendation. As the auction is for de-rated capacity and is technology neutral, this total capacity is offered for auction. Depending on bidding strategies, the composition of de-rated capacity that is successful may differ from that modelled without impacting security of supply.

3. The use of a cost optimisation approach, known as Least Worst Regret, to calculate the CM capacity to procure was supported.

   – This approach was used for the 2014 ECR and will also be used for the 2015 ECR.

4. Lack of information and understanding regarding Demand Side Response (DSR) that limits it to just reductions in demand and embedded generation.

   - For the 2015 FES we have undertaken an extensive review of distribution connected generation including micro generation in the home. This has enhanced our knowledge of the contribution from these technologies, and has been incorporated in the FES scenarios, but we still would welcome further detail on the back-up generation "behind the meter" that industry may have to provide DSR. There is currently no obligation on these sites to provide any information so until such information becomes available e.g. via aggregators or through the CM auction we have to assume that future use will be consistent with historical use which does allow for it as the metered demand off the transmission network is net of it.

5. The PTE expressed concerns over the level of station availabilities utilised in particular for CCGTs. ARUP were subsequently commissioned to benchmark our availability assumptions against markets where capacity is incentivised and this showed for all technologies except CCGTs the figures were robust although it's fair to say there is limited data on availabilities at peak times internationally.

   - For the 2015 ECR we have followed the same procedure in calculating station availabilities (consistent with CM Regulations for de-rating factors) but have adjusted the CCGT figure to move it within one percentage point of the international benchmark from ARUP by only considering data from very high demand periods (90^{th} percentile and above) and a reinstatement of a full maintenance program. For GB to be slightly lower than the benchmark is plausible due to the age and mode of operation of GB plant.

6. The final comment came out more in the discussions with the PTE rather than in their report and that related to weighting the sensitivities within the LWR calculation i.e. giving a lower weighting to certain sensitivities when compared to the FES scenarios.

   – For the 2015 ECR we have reviewed this by running the calculation with sensitivities weighted and found that unless sensitivities were given very low weightings they didn't affect the result. Hence as none of the sensitivities considered were either extreme or unlikely to occur weightings have not been incorporated in this year's analysis. Note that as reported in Annex 8.4.3, sensitivity analysis was carried out in which weightings were applied to the cold and warm winter sensitivities – this did not affect the outcome of the LWR calculation.

In conclusion National Grid is confident it has addressed where possible all the PTE's concerns within the approach being used for the 2015 ECR and as yet the PTE haven't raised any material concerns.

3.6 Quality Assurance

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

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

- **Interconnector flows** – Check the interconnector flow distributions and capacities
- **Scenario inputs** – Check the model input assumptions
- **Parameter Inputs** – Check the model setup assumptions
- **Scenarios to DDM Translation** – Check the input from the FES process into the DDM model
- **DDM model** – The model which will be used to calculate the LOLE and capacity to procure
- **DDM Outputs** - Check model outputs are consistent with inputs and scenario criteria
- **Capacity to Procure Process** – Check the inputs and outputs used to determine a range and recommended capacity to procure

The process is overseen by the PTE and they review and report on the overall process. Internally the process has governance under Director UK Market Operation.

For the details of the QA undertaken by National Grid see Annex 8.5.

4. Scenarios & Sensitivities

4.1 Overview

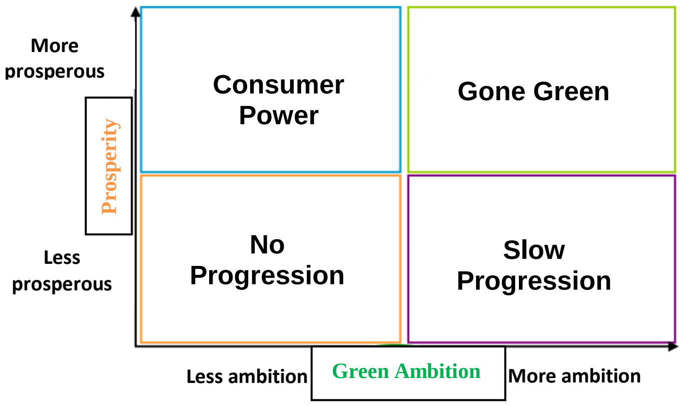
National Grid has a well-established and extensive consultation process on issues related to demand, generation and security of energy supply. This involves a continuous stakeholder consultation process with industry workshops, a summer seminar and bilateral meetings. As part of this process, a range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

- Future Energy Scenarios Stakeholder Engagement | National Grid
- Future Energy Scenarios | National Grid[17]
- Electricity Ten Year Statement | National Grid
- Gas Ten Year Statement | National Grid

This process results in the development of the Future Energy Scenarios (FES), derived using the latest information available on sources of supply and demand for both electricity and gas. The latest market intelligence is used to create the scenarios; for example, including the Transmission Entry Capacity (TEC) reduction announcements in March 2015, which are indications to National Grid that power plants have decided to reduce or increase the power that they will supply to the market.

For the 2015 FES, there are four scenarios based on the tri-lemma of supply security, affordability and sustainability. Security of supply for all scenarios is assumed not to exceed 3 hours LOLE from 2018/19 onwards, which leaves a 2x2 matrix to create the four scenarios. However, for this year we have replaced affordability and sustainability with Prosperity and Green Ambition. The axis of more or less prosperity provides a much clearer link to economic growth, and green ambition allows for more or less carbon reduction as well as flexing renewables.

Figure 5: Future Energy Scenarios Matrix



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

[17]Note that the 2015 document will be published on 15th July 2015

the Capacity Market analysis. In order to make further allowance for uncertainty in the coming years, the modelling has used a wide range of sensitivities.

For the purposes of modelling scenarios for the Capacity Market DECC's DDM model has been used, as described in Chapter 3.Thus while the non-Capacity Market technologies are fixed to the levels assumed in each of the FES scenarios, DDM calculates Capacity Market qualified capacity to ensure that the 3 hours LOLE Reliability Standard is met. Hence over time the capacities shown in this analysis may diverge from those in the original FES scenarios.

4.2 Scenario Descriptions

Descriptions of the four FES scenarios are detailed below with a high level summary of the resulting capacity technology split between CM and non-CM plant following the DDM runs shown in chapter 3. While DDM generates the final capacity figures required to meet the Reliability Standard for each scenario and sensitivity the FES scenarios are key inputs in determining the capacity to procure as they set the level of non-CM capacity which DDM then works around which explains the need to describe the assumptions behind each scenario.

4.2.1 Gone Green

Gone Green is a scenario where secure, affordable and sustainable energy sources are the main political objectives. There is more money available to both Government and consumers and this is used to progress towards the UK's environmental targets. The scenario takes a holistic approach to meeting the targets, assuming a contribution from the electricity, heat and transport sectors towards the 2020 renewable energy target.

Demand

Policy and innovation is focused on energy efficiency across the residential, industrial and commercial sectors, due to greater political certainty over Green Ambitions. From 2020 carbon reduction policy focuses more on the electrification of heating across all the three sectors. Technological innovation and a high level of prosperity leads to a high take up of electric vehicles. These all combine to initially reduce demand in the short term and then to increase demand from the early 2020s.

Generation

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

4.2.2 Slow Progression

Slow Progression is a scenario where secure, affordable and sustainable energy sources are the political objectives, but the economic conditions are less favourable than under Gone Green and so carbon reduction policies cannot be implemented as quickly.

Demand

Policy is focused on energy efficiency, due to greater political certainty over levels of Green Ambition but efforts are constrained due to less prosperity, leading to more “tried and tested” approaches being used with less innovation. Lower economic growth further hastens industrial demand decline. Both commercial demand and residential demand slowly increase due to an increasing population and slower uptake of energy efficiency measures. These all combine to leave demand remaining flat until around 2030.

Generation

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

4.2.3 No Progression

No Progression is a scenario where secure and affordable energy sources are the major political objective, because the economic conditions are less favourable than other scenarios and there is also less of a political focus on sustainability. This means that any additional carbon reduction policies are not expected to be implemented.

Demand

There is less political focus on energy efficiency due to political uncertainty over levels of Green Ambition. Lower economic growth hastens industrial demand decline further. Commercial demand slowly declines, as the relative cost of energy favours gas over electric heating. Residential demand slowly increases due to an increasing population and slower uptake of energy efficiency measures. These all combine to leave peak demand remaining flat until the mid-2020s.

Generation

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

4.2.4 Consumer Power

Consumer Power is a scenario where there is more prosperity but less political and social emphasis on sustainable energy policy. There is more money available in the economy for both consumers and Government, but there is a lack of political will for centralised carbon reduction policy.

Demand

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

Generation

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

4.3 Sensitivity Descriptions

To supplement the four FES scenarios and to cover both market and statistical uncertainties a range of sensitivities have been modelled by flexing a different variable each time. The following sections summarise the sensitivities analysed including some sensitivities considered but rejected.

4.3.1 Low Wind (at times of cold weather)

This sensitivity models the impact lower wind generation at times of cold weather (i.e. at times of high demand). To model this, a reduction in wind capacity across all onshore and offshore wind farms has been assumed which allows for correlation between cold weather and lower wind speeds. Recent statistical analysis undertaken by Durham University and Heriot-Watt University[18] validates the inclusion of this sensitivity.

4.3.2 High Plant Availabilities

The high and low plant availability sensitivities address the statistical uncertainty associated with determining the mean availabilities of each fuel type. The mean availabilities are determined based on the last 7 years, which is too small a sample size (i.e. just 7 data points) to be confident that the means of these distributions will be statistically representative of what could happen in the future. The plant availability sensitivities are not intended to address concerns of whether the base availability assumptions are too high or too low, and nor are they intended to make

[18] https://www.emrdeliverybody.com/CM/T-4-Auction-2015.aspx

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 reference scenario. For nuclear the availability increases from 82% to 89% and for CCGTs from 89% to 91% in 2019/20. These higher availabilities are based on one standard deviation above the mean of observed figures from the last seven years. Coal availabilities haven't been flexed as its availabilities show very little variance over the last seven years. In addition, other technologies haven't been flexed to allow for diversity as it would be unlikely all technologies would be simultaneously at their high availability levels.

Adjusting availabilities has an impact on the diversity of plant and therefore a small impact on the de-rated total. However, it clearly has a large impact on the name plate capacity total. These adjustments have been applied to the technologies that are both large in aggregate GWs and have shown variance across the sample. In addition to these sensitivities being the statistically correct thing to do, they also have the added advantage of providing greater granularity to the LWR calculation.

4.3.3 Low Plant Availabilities

This sensitivity along with the High Plant availabilities sensitivity are about addressing 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 lower mean availability than the reference scenario. For nuclear the availability reduces from 82% to 76% and for CCGTs from 89% to 87% in 2019/20. These lower availabilities are based on one standard deviation below mean of observed figures from the last seven years. Coal availabilities haven't been flexed as its availabilities show very little variance over the last seven years. In addition other technologies haven't been flexed to allow for diversity as it would be unlikely all technologies would be simultaneously at their low availability levels.

4.3.4 Interconnector Assumptions & Sensitivities

Note that for the 2015 ECR interconnector capacities are based on the FES scenarios (see section 4.5.5) and the flows are calculated as part of the stochastic modelling hence there is no requirement for interconnector sensitivities.

4.3.5 Weather – Cold Winter

The cold weather sensitivity addresses the uncertainty of demand due to cold winter weather conditions. Demand is highly sensitive to weather and a cold winter will lead to higher demand that 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 the last 10 years. This is too small a sample to be confident that the demand distributions will be statistically representative of future weather conditions. For example, the Met Office uses a much longer period of 30 years when calculating average temperatures.

The cold weather sensitivity is based on a recent cold winter and calculates LOLE assuming that the weather that occurred in 2010/11 is repeated. This winter was not extreme and when compared to the last 30 years, we would expect similar weather every 1 in 5 years. If a longer history is assumed (90 years) then such weather conditions are actually close to average but due to global warming a 30 year history is a more suitable basis.

There are two further reasons why this sensitivity is included. Firstly, LOLE is a first order metric, which is highly non-linear and so not including the sensitivity fails to fully account for the non-linear impact of increasing LOLE and therefore understates its impact. This can be easily illustrated by considering two hypothetical scenarios both of which meet the Reliability Standard but have significantly different impacts.

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

The final reason for including this sensitivity is reputational as this sensitivity is clearly credible given that the winter was less than 5 years ago and wasn't extreme and from a practical communications point it would be extremely difficult to defend a position that didn't consider it in the calculation.

4.3.6 Weather – Warm Winter

This warm weather sensitivity is included on the same statistical basis as cold weather, and ensures that the treatment of the uncertainty of demand due to weather is unbiased. The warm weather sensitivity is based on a recent warm winter and calculates LOLE assuming that the weather that occurred in 2006/07 is repeated. This winter was not extreme and when compared to the last 30 years, we would expect similar weather every 1 in 15 years.

4.3.7 High Demand

This sensitivity covers the uncertainty of the underlying (i.e. weather-corrected) ACS peak demand forecast. This adjustment is based on historical forecasting performance for the winter ahead (average error and standard deviation over the last 7 years) and assumes an increase of +0.9% to the FES ACS peak demands. For details of this metric see Annex 8.6.

4.3.8 Low Demand

This sensitivity covers the uncertainty of the underlying (i.e. weather-corrected) ACS peak demand forecast. This adjustment is based on historical forecasting performance for the winter ahead (average error and standard deviation over the last 7 years) and assumes a decrease of -3.3% to the FES ACS peak demands. For details of this metric see Annex 8.6.

4.3.9 Sensitivities considered but rejected

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

Mothballed Plant – This is viewed more as a shorter term sensitivity i.e. prior to the Capacity Market. This is because once the CM is in place it would be unlikely that any mothballed plant would be available to return to the market or operational plant that had opted out and were operational would then mothball rather than close. In any case as more information came to light over time they could be allowed for in the T-1 auction. Hence it was agreed not to include this sensitivity.

Nuclear Type Fault – This considered whether the type faults seen in 2014 should be covered by a separate sensitivity. The problems at Heysham 1 and Hartlepool (which reduced capacity at these plants by up to 30% over winter 2014/15) were a good example of a type fault – one that affected a particular design of reactors. The AGRs were generally built in pairs of the same design. Similar type faults have also affected Hinkley Point B and Hunterston in the past. Our research suggested no pattern existed and that there was a low incidence of such type faults over the winter period. Hence it was agreed not to include this sensitivity.

CM and CfD Plant Slippage - This sensitivity was designed to reflect slippage in awarded plant away from their connection dates similar to what has been seen in the past for new plants connecting. However, following discussions with DECC it was decided that the agreements provide enough incentive to ensure connection dates are met and if they aren't the volume can be covered by the T-1 auction. In addition any slippage in CfD plant is covered by the range of renewable generation connecting across the four FES scenarios. Hence it was agreed not to include this sensitivity.

4.4 Demand Methodology

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

- Domestic
- Industrial
- Commercial
- Other/Sundry

4.4.1 Domestic

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

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

4.4.2 Industrial

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

4.4.3 Commercial

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

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

4.4.4 Other/Sundry

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

4.4.5 Peak Demands

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

- Electric vehicles – based on the projected numbers, the potential user groups are assessed, how and when they could be charging (constrained and unconstrained), and data from recently published trials are incorporated.
- Heat pumps – using the number of heat pumps and heat demand, data from manufacturers and trial within day profiles combined with performance statistics and historical weather trends are used in order to determine the electrical heat demand at peak.
- Micro-generation – using the projection capacities by type and a peak load factor assumption, an assessment on the micro-generation levels at peak.
- Losses – as with annual demand, this is a function of total peak demand.
- Industrial & Commercial Demand Side Response – created using desktop research and assumptions of future efficiency improvements.
- Domestic peak response – as with annual demand this starts with the smart meter roll out numbers, project outcome data and perceived customer engagement rates. From this results a percentage peak demand reduction. This percentage factor is then applied to the peak demand.

4.4.6 Calibration

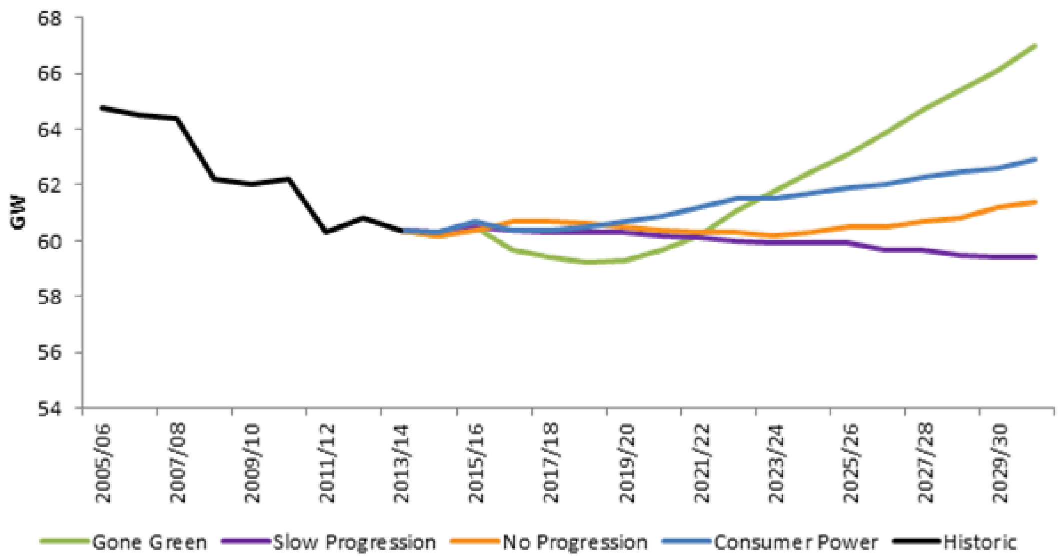
Both annual and peak demands are calibrated. Annual demands are calibrated to the previous year's historical annual demand figures as published by DECC. Peak demand is calibrated with weather corrected metered transmission demand.

4.4.7 Results

The results of the described methods provided are shown below in Annex 8.2.1. For a more detailed description of the FES scenarios please refer the FES document[20]; however, note that the demand is defined differently in the FES document to that shown below which is unrestricted end consumer demand plus losses excluding exports and station demand.

[20] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

Figure 6: Demand at Peak by Scenario



4.4.8 Demand Side Response

In the Future Energy Scenarios (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.

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

All the FES scenarios assume a 1GW Triad assumption consistent with the actual for 2014/15. Modification to the Balancing and Settlement Code will require certain businesses to be settled half hourly which should introduce a driver for businesses to use less power at peak, as power prices should be at their highest.

From winter 2018/19 those DSR providers which have an agreement under the capacity market will be available and, it is assumed, they will remain in place thereafter. In the same year, we believe that DSR under Short Term Operating Reserves (STOR) will be available to the Capacity Market, where they will be able to access additional revenues. Thereafter new markets and revenue streams will open up, as a result of this changing environment, with profiles trending downwards towards their maximum reduction values, which they all achieve by 2030. The rate of change depends upon the scenario's conditions.

For the Gone Green scenario, a higher technical uptake rate and a higher utilisation rate of DSR is assumed. This is because the price of electricity will be high, there will be greater peak demand and hence there will be relatively larger savings to be made. There will also be a greener ambition to encourage such behaviour changes. In No Progression the cost of power will be lower and so the savings will be much less; consequently, a lower figure is assumed. For Slow Progression and Consumer Power mid-ranges are assumed.

The projections of the industrial and commercial DSR profile reductions have changed since the last FES publication. Figure 7 and Figure 8 illustrate the differences with the main change being in the actual which saw a fall from 1.5GW to 1GW. (In Figure 8, the Slow Progression values are the same as Consumer Power).

Figure 7 : FES 2014 Industrial and Commercial DSR reduction

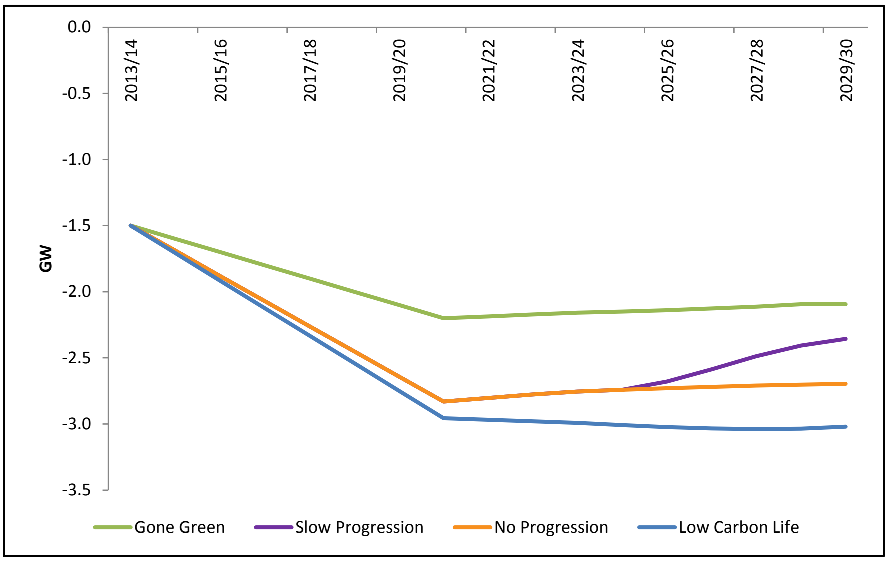
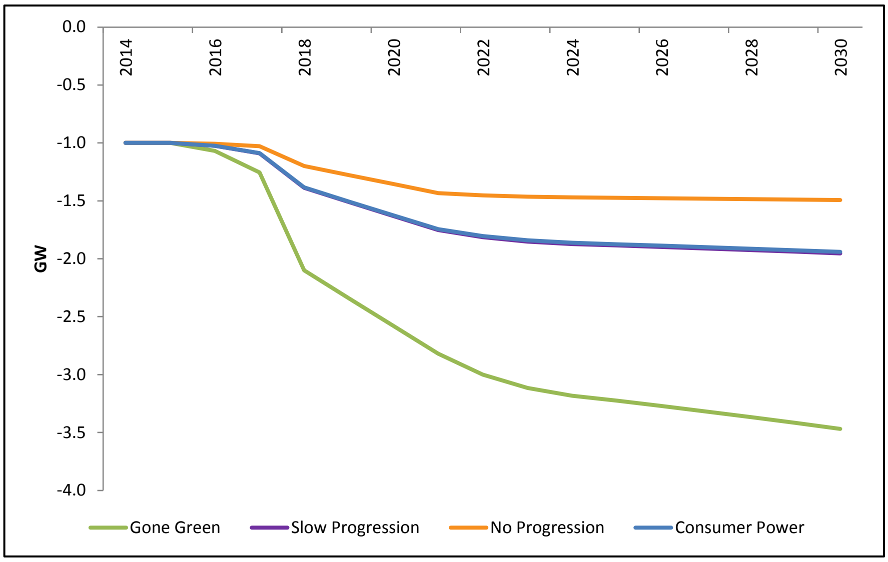


Figure 8: FES 2015 Industrial and Commercial DSR reduction



However, it should be noted that the peak demand is based, primarily, upon the annual demands. The annual demands for the commercial and industrial sectors have undergone some revision as a result of the new Arup model that has been utilised. ARUP and Oxford Economics have created a new model that looks in more detail at the impact on energy demand from changing economic situations and retail prices. This model has changed the ordering of the annual demands for the different scenarios.

FES 2014

In 2014 the main source used for the impact of DSR was based upon an Element Energy Study: Demand Side Response in the non-domestic sector[21]. This study gave a range of potential savings which were averaged out to give two potential saving values of 3.8% and 7.9%. Consumers were assumed to engage with DSR up to 2020 in order to reduce their costs. Thereafter there is a drop off, or levelling off (depending on the scenario), as increasing energy efficiency reduces the amount of demand which may be temporarily reduced.

Market Intelligence for FES 2015

This year more information is available to build a more reliable model:

Triad Avoidance

There is around 0.5GW difference in the starting points of the graphs based on FES 2014 and FES 2015, respectively. This starting point is based upon an estimated figure for the amount of Triad Avoidance which takes place during the peak period. The exact value is unknown as it is the cumulative effect of a number of business acting independently of each other and network operators. The value is estimated by National Grid's Commercial Operations team, based upon observed changes to the use of the network. This assumed value forms the basis for all the subsequent figures.

Demand Shifting

A wider reaching literature review was undertaken to establish if there were more sources of information available. It transpired that there were more projects, reviews and trials available. However the robustness and scope of the projects made it difficult to draw clear conclusion and few, if any, were based upon actual trial data over a sufficiently long time period with a large enough data set. Because of the paucity of data we have used high medium and low values from the reports. These values were then applied to component parts to the demand shifting, namely:

- Discretionary Load
- Technical Take-up
- Utilisation Rate

Capacity Market

Results of the Capacity Market auction have been utilised in the modelling. The various criteria of proven, unproven, cleared and failed have been used, where appropriate, for the different scenarios.

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[21] http://www.flexitricity.com/file/Ofgem%20DSR%20in%20the%20non-domestic%20sector%20-%20final%20report_30_05_12.pdf

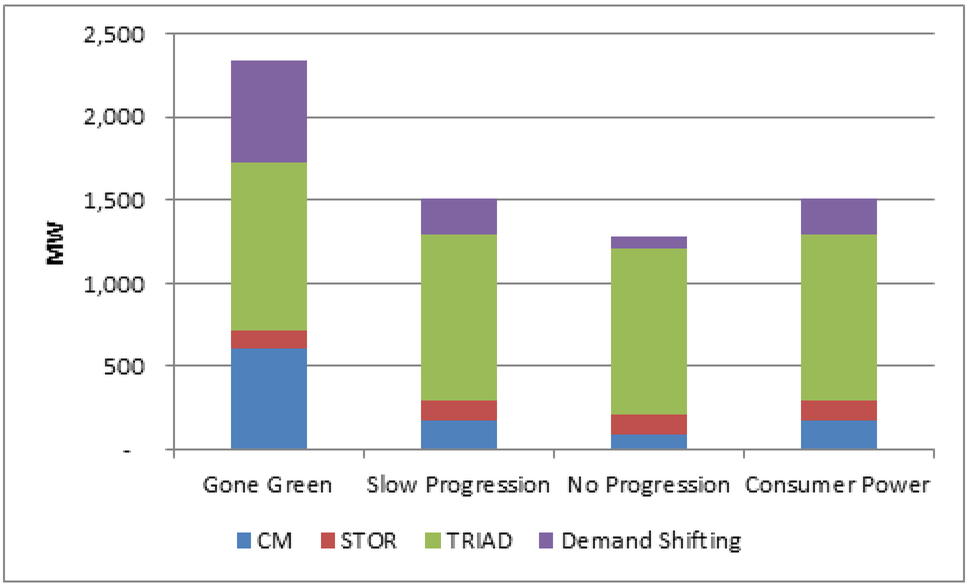
STOR

Data from National Grid's balancing service have also been used, in particular the Short Term Operating Reserves. This is anticipated to reach its maximum transition from STOR to the capacity market by 2021.

2015 FES Outcomes

As a result of the additional input information we have a more accurate output, as is seen in Figure 8. The component parts that make up DSR in our scenarios for 2019/20 are given in Figure 9

Figure 9: Component parts of 2019/20 scenario DSR profiles



The range of DSR over the four FES scenarios in 2019/20 is from 1.3GW to 2.3GW with the LWR marginal case being Consumer Power which has a DSR figure of 1.5GW.

4.5 Generation Methodology

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

The scenario narrative and primary assumptions provide the uncertainty envelope that determines the emphasis placed on the different types of generation technology within each scenario. Each power station will then be placed accordingly within their technology stack.

The placement of a power station will be determined by a number of factors, such as market intelligence, Government policy and legislation. Project status and economics, which are applicable to that particular power station, were also taken into account.

The contracted background or Transmission Entry Capacity (TEC) Register[22] provides the starting point for the analysis of power stations which require a connection to the National Electricity Transmission System (NETS). It provides a list of power stations which are using, or planning to make use, of the NETS. Although the contracted background provides the basis for the majority of the entries into the generation backgrounds, the analysis is not limited to generators with a signed connection agreement. Other projects where information has been received about in the very early phases of scoping pre connection agreement are also taken into account.

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

The generation backgrounds are then built up to meet the Reliability Standard whilst staying within the allowed Levy Control Framework (LCF) spend limits.

4.5.1 Contracted Background

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

4.5.2 Market Intelligence

This section covers how market intelligence gathered through stakeholder engagement along with more general information is used to help determine which renewable generation as well as non-renewable plant is likely to process to a connection that could affect the FES period including out to 2019/20 and therefore the capacity to procure.

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?

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

Technology

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

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

Financial Markets

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

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

4.5.3 FES Plant Economics

This area is a key feed in to the power generation backgrounds and explores economic viability and how a particular plant or group of plants could operate in the market now and in the future. The Short Run Marginal Cost (SRMC) of the existing power station fleet has been the focus of the 2015 analysis.

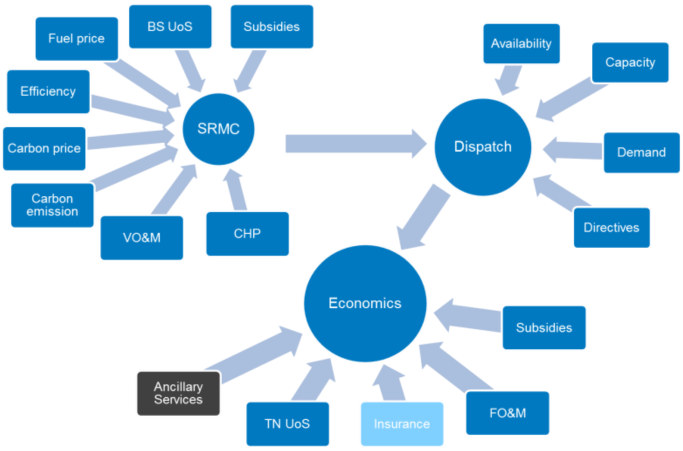
The model calculates the SRMC for transmission connected power stations which will be used to inform the power generation backgrounds:

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

The model also identifies the level of fuel prices required for power stations to financially breakeven.

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

Figure 10: Flow diagram for transmission generation background



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

4.5.4 Project Status

The project status is especially important when determining at what point in time a new generator may connect to the NETS. For a new plant, factors such as whether a generator has a signed 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.

4.5.5 Interconnector capacity Assumptions

Capacity levels and flows for peak and annual periods are produced for each scenario. These are inputs to the power demand and generation processes. Export flows (i.e. flows out from GB) are treated as demand and import flows (i.e. flows into GB) are treated as generation.

The installed capacity in FES 2015 has increased from FES 2014 due to greater regulatory certainty and the progression of specific projects. Annually GB is a net importer of power in all scenarios. The peak flows are the contributions from interconnected markets at times of low GB capacity margin. The difference in peak flows between scenarios is largely dependent on the level of interconnector capacity.

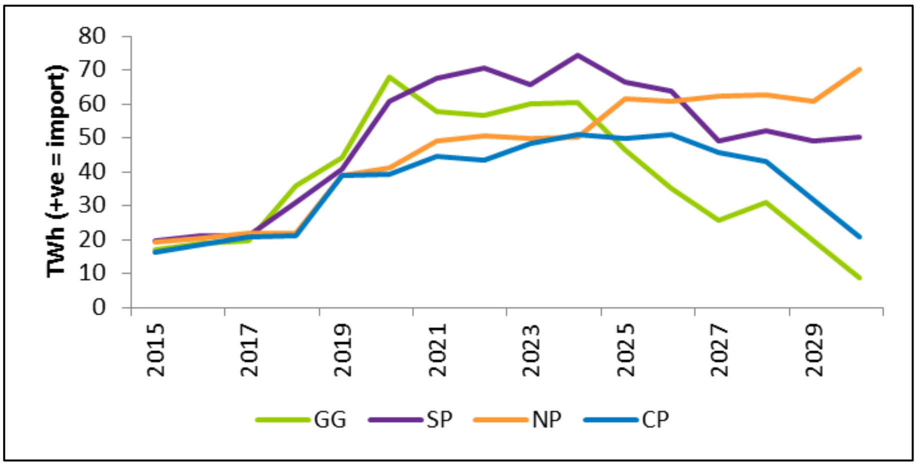
Table 6: Capacity levels for interconnection

	Gone Green		Slow Progression		No Progression		Consumer Power	
	FES 2015	FES 2014	FES 2015	FES 2014	FES 2015	FES 2014	FES 2015	FES 2014
2018/19	6	5	5	4	4	4	4	4
2019/20	**7**	6	**6**	5	**6**	4	**6**	5
2020/21	10.8	6	8.4	6	6	5	6	5
2030/31	17.7	11.8	14.2	8.4	9.8	7.4	10.8	7.4

The FES interconnector capacity levels have increased considerably from FES 2014 and the table above offers a comparison. The current capacity level is 3.75 GW but is expected to increase substantially in the future and, although the biggest increases are later, there is still almost a doubling of capacity by 2019/20 in the Gone Green scenario. The change is a consequence of Ofgem's decision to introduce the cap and floor regime in 2014. This has provided greater regulatory and investment certainty and has acted as a de-risking mechanism, demonstrated by the recent progression of new interconnector projects.

Ofgem's cap and floor regime will drive the capacity level towards the non-binding EU capacity targets. These targets are based on a percentage comparison to the level of installed generation capacity. For 2020, the target is 10% and Gone Green is the only scenario where this is met.

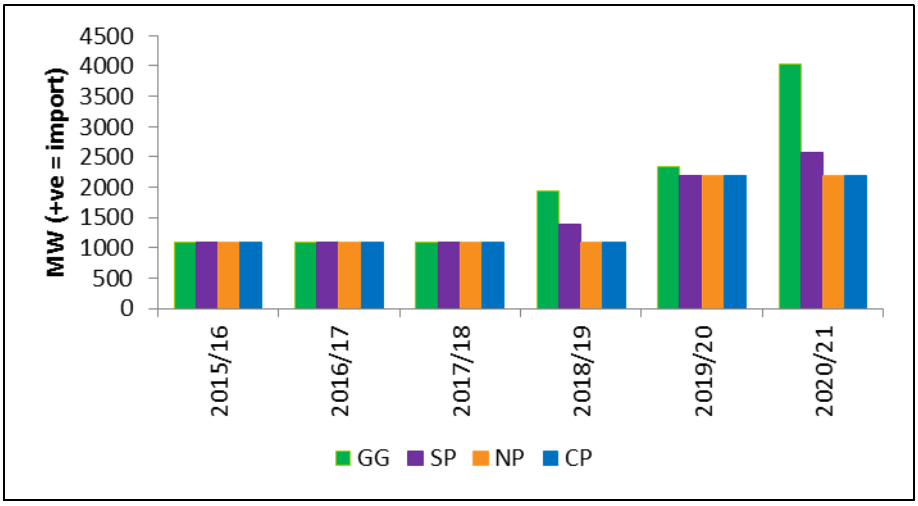
Figure 11: Annual interconnector flows



In the short term, annual imports rise rapidly in line with the increase in capacity. Across all four scenarios GB remains a net importer of electricity due to the price differential with connected countries. The carbon price support is a major factor in this price differential. Increasing levels of both nuclear and intermittent generation increase the times when price differentials favour exports resulting in lower net imports from the mid-2020s onwards in 3 of the scenarios. Conversely, in No Progression, which has much lower levels of intermittent generation than Gone Green, net imports continue to increase until the 2030s.

Annual flows were modelled using a version of National Grid's Electricity Scenario Illustrator (ELSI) model with the addition of nodes to represent each connected country. ELSI is a GB electricity network simulation model. Prices for these interconnector nodes were obtained from Baringa who ran their European model using scenarios mapped to National Grid's 2014 FES scenarios and adjusted for FES 2015 fuel price assumptions.

Figure 12: Peak interconnector flows



The peak flows represent a major change from the 2014 FES which assumed net float at peak with exports to Ireland exactly offset by imports from the continent. For 2015 FES the peak flows are the typical levels expected at times of low or negative GB capacity margins. **However, it should be noted that these peak figures aren't used in the CM modelling as that uses distributions from Baringa's pan-European market model.**

The flows are calculated by multiplying the capacity levels with assumed de-rating factors. The starting point for the de-rating factors was the Pöyry report for DECC described in more detail in section 7.2.2. The capacity market de-rating factors and associated analysis, described in the same section, were not available at the time the FES interconnector flows were required. The timing and non-GB location of the capacity levels may affect the de-rating factors used with potentially lower de-ratings following each additional connection to a country. The majority of the new interconnectors are expected to connect from 2020 onwards and so this assumption will have little impact on the analysis for 2019/20.

The purpose of the Pöyry report was to provide minimum de-rating factors for the capacity auctions based on historical analysis. As such the Pöyry de-rating factors are deliberately conservative. They were based on the percentage of time interconnectors imported to GB over a large number of days but not the flows that could be expected. Adjustments were made to these factors to better reflect the flows we might expect when GB capacity margins are low and the final values were validated against actual flows. For example the Pöyry report gave a wide range of possible factors for France with the most appropriate for their purposes being 29%. For FES 2015 a higher de-rating factor of 62% was used based on the results for 2012/13 and 2013/14 as these two years demonstrated a step change in the relationship between price differentials and flows brought about in part by the introduction of market coupling. For the Netherlands this affect was less profound so a longer time series was used. The Pöyry de-rating factors for new interconnectors did not include any allowance for technical availability so for FES a reduction was applied. For Ireland Moyle is assumed to return to full capacity by 2019/20 and export in line with Eirgrid's stated view and exports via EWIC fall to zero by 2019/20 due to progressive market coupling.

Interconnector flows are the result of a complex interaction between generation and demand across Europe, subject to network constraints. Ideally this would be stochastically modelled to reflect the full range of weather, demand and generation that could occur and provide additional information such as LOLE. At the present time National Grid do not possess a suitable model or the detailed data required for this comprehensive level of analysis. Whilst progress is being made towards these goals for future years an interim approach has been developed for the FES scenarios. Section 7.2.3 gives more detail on planned improvements in our modelling capability.

4.5.6 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. Or it could be in the form of market wide mechanisms to develop, for example flexible generation, such as the upcoming Capacity Market.

Energy legislation enacted at European and national level will impact what power supply sources are developed and connected to the NETS. For example, the renewable energy target for 2020 is intended to reduce reliance on high carbon fossil fuels by promoting renewable sources, making it very likely that the NETS will experience much more intermittent renewable capacity. Another example is the plant that may have to be modified to comply with environmental directives, such as the Large Combustion Plant Directive and Industrial Emissions Directive. This legislation places restrictions on the number of running hours for fossil fuel power generation plants with regard to the harmful waste gases that they emit, unless investments are made to reduce this impact, and will affect decisions on whether to invest in new plants or maintain existing facilities.

4.5.7 Reliability Standard

The power generation backgrounds were developed for each of the scenarios based on the information gathered, as explained above. The 2015 power generations backgrounds are developed to both meet demand and to meet the Reliability Standard of 3 hours LOLE. In the years up to 2017/18, the generation backgrounds are driven by more granular intelligence and therefore LOLE can vary quite significantly year to year within this period. If during 2015/16 if LOLE is predicted to rise above 3 hours then National Grid, DECC and Ofgem have agreed the implementation of New Balancing Services to meet the Reliability Standard with discussions progressing on options for 2016/17 and 2017/18. From 2018/19 onwards, the backgrounds are developed to meet 3 hours LOLE.

This means that post 2018/19, taking into account the probability of power sources being available at times of system stress, there will be on average an expectation (over a number of years) of 3 hours when supply doesn't meet demand. Note that this standard is set before any mitigating actions (voltage reduction, max gen service and Emergency Assistance from interconnectors) are instigated which would need to be exhausted before there are any controlled disconnections.

When calculating LOLE the ACS peak demand (transmission excluding exports and station demand including demand met by embedded wind) is used. The largest potential loss of load is added to the demand figure in the FES modelling to cover the sterilisation of plant required to ensure network integrity.

5. Recommended Capacity to Procure

5.1 Why is a Recommended Capacity Required?

As a key component of the Government's EMR package, the introduction of the Capacity Market from 2018/19 onwards must be done in a way that ensures the required security of supply is achieved in a cost effective manner.

To inform the level of capacity to procure in 2019/20 via the Capacity Market auction later this year, the Government requires National Grid to provide it with a recommendation based on the analysis of a number of scenarios and sensitivities that will ensure its policy objectives are achieved.

A key aim of the analysis to date has been to help the Government understand how different scenarios would impact on its objectives and ambitions, so that it can take informed decisions. The modelling approach adopted for the EMR Capacity Market analysis is described in detail in Chapter 3, including the data, assumptions and models utilised with the scenarios and sensitivities that have been run through the model detailed in Chapter 4. These scenarios and sensitivities investigated, offer a range of likely demand and generation outcomes that are intended to meet the required security of supply as set out by Government policy.

5.2 Approach to Use and Rationale

If the probability of each potential future energy outcome could be estimated accurately, then the recommended de-rated capacity to procure could potentially be calculated by weighting the potential choices with the relevant probabilities. However, it is not practically possible to assign probabilities or weightings to each scenario and sensitivity and hence a different approach is required.

For the 2014 ECR, a number of approaches were considered to determine the recommended capacity to procure. When considering the various approaches, National Grid received advice from the DECC Panel of Technical Experts (PTE) and also consulted the wider industry at a National Grid Industry Implementation Workshop. There was wide ranging agreement that a Least Worst Regret approach (based on minimising the maximum regret costs of over or under procuring capacity) was the most appropriate to use for recommending a level of capacity to procure. It was also felt that the assumptions that feed into this approach should be publicly available and not derived from the modelling undertaken by National Grid e.g. it should use the published Value of Lost Load (VoLL) and the demand Curve net CONE value (cost of new entry for a CCGT).

For the 2015 ECR, the same Least Worst Regret approach has been utilised for recommending a capacity to procure. A description of the assumptions used is shown below. Further details on the approach can be found in Annex 8.4.

In order to determine the maximum regret cost for a particular case, a view on the unit de-rated capacity cost and unit cost of unserved energy is required. Costs obtained directly from the modelling have not been used; furthermore, the auction process itself will determine the outturn costs.

For the analysis, the following has been used (2012 prices): VoLL (Value of Lost Load) = 17,000 £/MWh as the unit cost of Expected Energy Unserved (EEU) and net CONE (cost of new entry) = 49,000 £/MW/year[23] as the unit cost of de-rated capacity. The VoLL and a similar de-rated capacity cost was used to determine the Reliability Standard[24].

The total cost of a case (scenario or sensitivity) is calculated as:

Total Cost = Cost of De-Rated Capacity to Procure + Cost of EEU

where:

Cost of De-Rated Capacity to Procure = De-Rated Capacity Procured (MW) * Unit cost of De-Rated Capacity (£/MW)

and:

Cost of EEU = EEU (MWh) * Unit Cost of Unserved Energy (£/MWh)

The cost of the 5.5 GW of capacity already procured for 2019/20 in the 2018/19 T-4 auction is excluded from the above calculation as it is the same cost for all scenarios and sensitivities and has no impact on the Least Worst Regret calculation.

A worked example of the calculations is shown in Annex 8.4.2.

To test the stability of these calculations, sensitivity analysis was carried out in which the VoLL, cost of capacity and other options were flexed to see the potential impact on the LWR outcome (see Annex 8.4.3 for further details). However, our recommendation is based on the agreed methodology of using the CM parameters as specified by the Demand Curve from DECC i.e. £17,000/MWh for VoLL and 49,000 £/MW/year net CONE for the cost of capacity.

[23] As outlined in the EMR Stakeholder bulletin issued on May 14th 2014

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

6. Results and Conclusions

6.1 Overview of results and metrics

This chapter presents the results from the modelling of the scenarios and sensitivities outlined in Chapters 4 and 5. This chapter concentrates on 2019/20 with the exception of section 6.1.7 which details capacity levels out to 2029/30. Further information on future years can be found in Annex 8.2.

6.1.1 Scenarios and sensitivities

The assumption is that the FES scenarios will cover uncertainty by incorporating ranges for annual and peak demand, DSR, interconnection and generation with the sensitivities covering uncertainty in station peak availabilities, weather, wind and peak demand forecast performance.

In deciding which scenarios to use as reference cases to run sensitivities from, a number of factors were considered:

- There is no “central view” of the four FES scenarios.
- At least two should be run to reduce any potential bias associated with using only one.
- Ensure the scenarios chosen use a range of low carbon/renewable deployment (FES range is around 3GW of nameplate capacity in 2019/20) and that resulting Capacity Market qualifying capacities are not the highest or lowest of the four scenarios.
- Avoid using scenarios at the edge of the range as this will further extend the range beyond the range derived from applying the sensitivities to the central scenarios to avoid disproportionally affecting the outcome of the Least Worst Regret calculation.

The two scenarios that best meet these criteria were Slow Progression and Consumer Power. Therefore these two scenarios were chosen as reference cases for the purpose of applying sensitivities. They were combined with the full range of sensitivities and the other two FES scenarios to calculate the recommended capacity to procure. Note that the LOLE from the two reference cases should not be used to assess whether or not the security standard has been met since these are only two of many credible outcomes in 2019/20.

DECC’s scenario was modelled but not included in the calculation of the recommended capacity to procure since this recommendation is based solely on National Grid’s independent analysis. However, excluding DECC scenario from the calculation has no impact on the recommended capacity.

The DECC Scenario is based on the reference scenario from the 2014 Energy and Emissions Projections[25], which kept within the LCF limits while meeting the Reliability Standard. Annual demand projections are still consistent with 2014 EEP, while for the

[25] https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2014

purpose of the ECR there have been some amendments to include the results of the December 2014 Capacity Auction and the February 2015 CfD Allocation round.

The following table shows the modelling results sorted in order of capacity to procure to meet the 3 hours LOLE Reliability Standard. Note that this capacity excludes the 5.5 GW[26] already procured for 2019/20 in the 2018/19 T-4 auction (3.1 GW with 3 year CM Agreements, 2.4 GW with 14/15 year CM Agreements).

Table 7: Modelled de-rated capacities and peak demands

Name	Graph Code	Capacity to Procure (GW)	Outside CM (GW)	Total derated capacity (GW)	ACS Peak (GW)
Slow Progression low demand	SP_LOW_DEMAND	46.1	14.8	60.8	58.3
Consumer Power low demand	CP_LOW_DEMAND	46.1	15.2	61.4	58.7
DECC Scenario	DECC	46.2	15.1	61.3	58.9
Slow Progression warm winter	SP_WARM	46.4	14.7	61.1	60.3
Consumer Power warm winter	CP_WARM	46.5	15.1	61.6	60.7
Gone Green	GG	47.0	15.0	61.9	59.3
Slow Progression high availability	SP_HIGH_AVAIL	47.7	14.8	62.5	60.3
Consumer Power high availability	CP_HIGH_AVAIL	47.9	15.2	63.1	60.7
Slow Progression	SP	48.0	14.8	62.8	60.3
Consumer Power	CP	48.1	15.3	63.4	60.7
Slow Progression Low availability	SP_LOW_AVAIL	48.2	14.8	63.1	60.3
Consumer Power Low availability	CP_LOW_AVAIL	48.3	15.3	63.6	60.7
Slow Progression high demand	SP_HIGH_DEMAND	48.5	14.8	63.4	60.8
No Progression	NP	48.6	14.3	62.9	60.5
Consumer Power high demand	CP_HIGH_DEMAND	48.7	15.3	64.0	61.2
Slow Progression low wind	SP_LOW_WIND	48.8	14.0	62.8	60.3
Consumer Power low wind	CP_LOW_WIND	48.9	14.5	63.4	60.7
Slow Progression cold winter	SP_COLD	49.0	14.9	63.9	60.3
Consumer Power cold winter	CP_COLD	49.1	15.4	64.4	60.7

Scenario Colour Key

Gone Green
Slow Progression
No Progression
Consumer Power
DECC Scenario

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

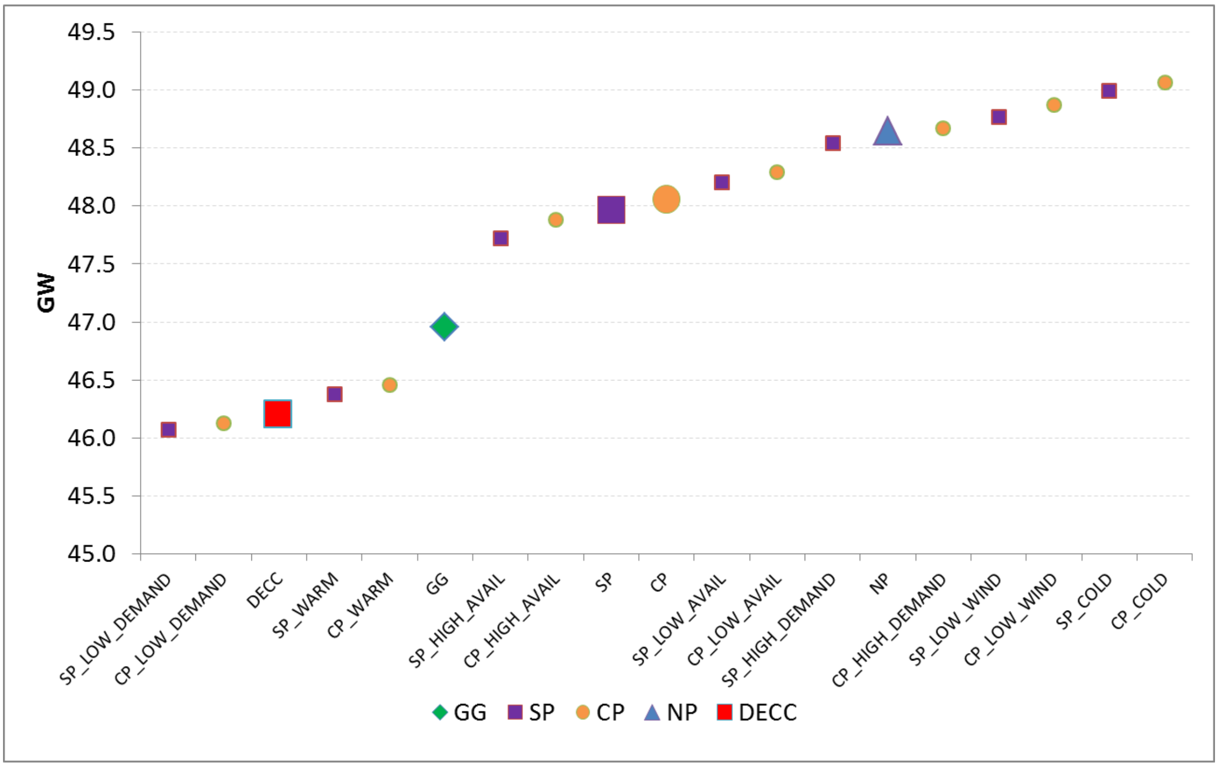
N.B. ACS Peak demand excludes reserve for largest infeed loss. Capacity to procure excludes 5.5 GW already procured for 2019/20 in the 2018/19 T-4 auction – this 5.5 GW value is included in the "Outside CM" capacity.

[26] see pages 9 and 10 in https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202014%20Final%20Auction%20Results%20Report.pdf

6.1.2 Capacity to procure range

Low demands and cold winters define the extremes of the capacity to procure range. The following chart shows this range for all National Grid scenarios and sensitivities plus the DECC scenario. Individual scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded.

Figure 13: Capacity to procure range plus DECC scenario



6.1.3 Under procure v Over procure

The table and figure above show the capacity required to meet 3 hours LOLE in each model run. However, if capacity was selected based on one model run but in 2019/20 the actual conditions matched a different model run then capacity will have either been over or under procured resulting in an LOLE higher or lower than 3. The impact of over or under procuring capacity can be estimated from the cost of capacity and the cost of unserved energy.

In accordance with the agreed methodology, a cost of capacity of 49,000 £/MW/yr (based on the net CONE for a new CCGT in 2012 prices) and an energy unserved cost of £17000/MWh has been used for the purposes of recommending a capacity to procure (and to illustrate these results) since our recommended capacity to procure corresponds to the value on the CM demand curve for the net CONE capacity cost. Actual capacity costs will be derived from the auction clearing price and could vary significantly from a range of below 25,000 £/MW/yr (the auction cap for price takers) to 75,000 £/MW/yr (the auction cap for price makers).

The total cost of a case (scenario or sensitivity) is calculated as:

Total Cost = Cost of De-Rated Capacity to Procure + Cost of EEU

where:

Cost of De-Rated Capacity to Procure = De-Rated Capacity Procured (MW)
* Unit cost of De-Rated Capacity (£/MW)

and:

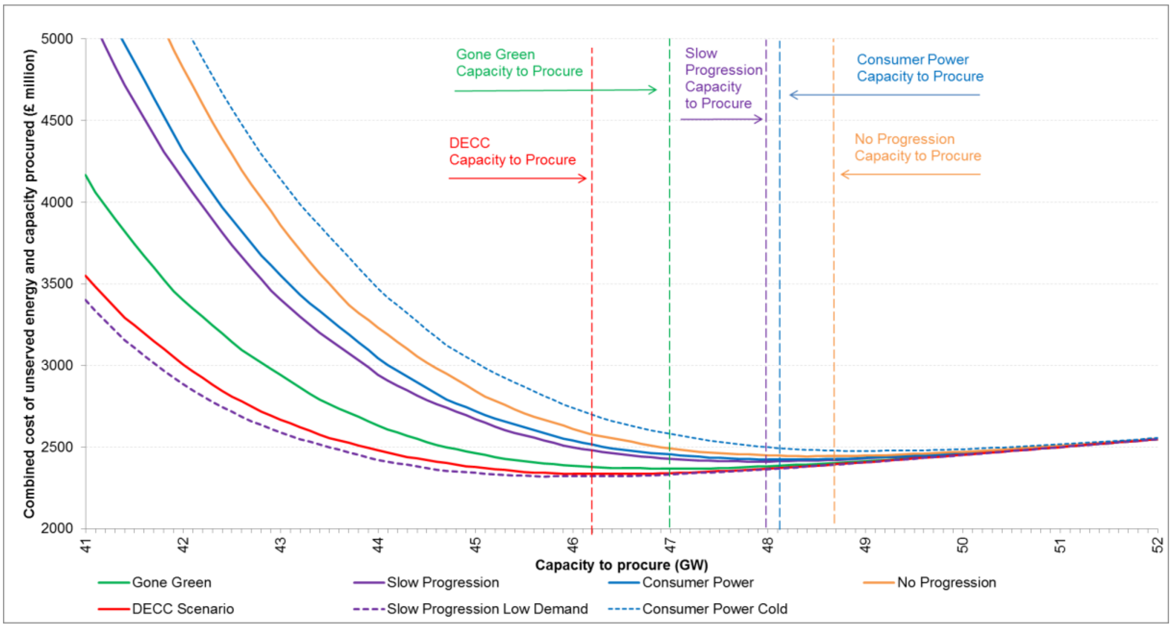
Cost of EEU = EEU (MWh) * Unit Cost of Unserved Energy (£/MWh)

The cost of the 5.5 GW of capacity already procured for 2019/20 in the 2018/19 T-4 auction is excluded from the above calculation as it is the same cost for all scenarios and sensitivities.

The impact of over or under procuring is not symmetrical. The cost of under procuring capacity is much higher than over procuring due to the non-linear relationship between unserved energy cost and capacity cost. This happens because the lower the capacity the greater the number of half-hours where demand exceeds available capacity. The cost of capacity is assumed to be linearly related to capacity procured in this analysis. The actual cost of capacity will depend on the marginal generation purchased in the auction and this could potentially increase for higher levels of capacity, particularly if the technology changes. The auction is pay-as-clear, so an increase in the clearing price will affect the costs of all capacity procured, and not just the marginal capacity. Detailed cost analysis is outside of the scope of this report.

The following chart of total cost against procured capacity shows costs falling steeply as energy unserved falls but once there is sufficient capacity the unserved energy cost is low and costs start to grow at a linear rate as extra capacity is added (since a constant unit capacity cost has been used). The optimal capacity for any one case will be around the bottom of the total cost curve for that case. Note that the capacity costs associated with the supply curve in the auction are likely to rise in a non-linear way reflecting the increase in unit capacity costs along the supply curve.

Figure 14: Combined cost of energy unserved and procured capacity against capacity to procure



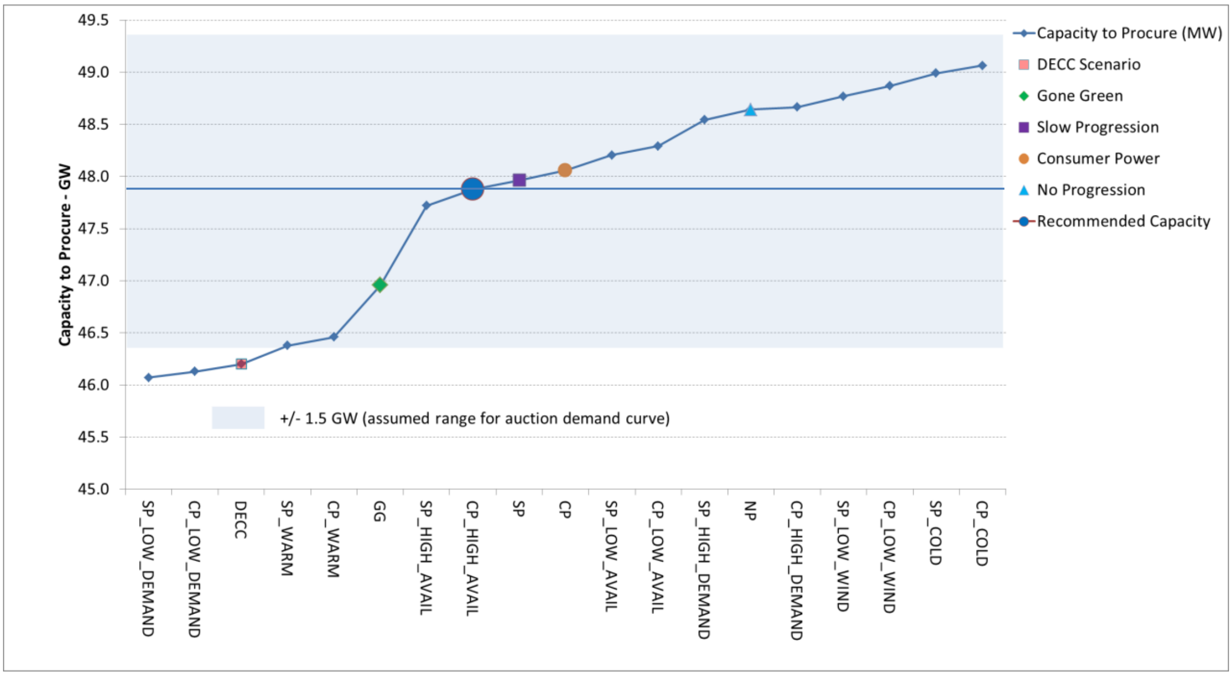
6.1.4 Least Worst Regret

Least Worst Regret is a methodology that selects a single capacity to procure in 2019/20 for all potential outcomes. The methodology is explained in chapter 5 with a worked example in Annex 8.4. It uses a scenario/sensitivity combination from which the recommended capacity to procure is derived.

The outcome of the Least Worst Regret calculation applied to all of National Grid's scenarios and sensitivities is a recommended capacity to procure for 2019/20 of **47.9 GW** derived from the requirement of the Consumer Power High Availability sensitivity. As previously stated, this does not take account of a different clearing price to net CONE resulting from the auction as our recommended target capacity to procure corresponds to the value on the CM demand curve for the net CONE capacity cost. Any discrepancy in outcome based on the slope of the demand curve can be reconciled appropriately in the T-1 auction.

The following chart illustrates the full range of potential procurement options and identifies the Least Worst Regret recommended capacity. It also shows the potential range that could be procured in the 2019/20 T-4 auction assuming a target capacity of 47.9 GW and a Demand Curve tolerance range of +/- 1.5 GW around the target (chosen by the Government based on the size of a typical large CMU and as an anti-gaming measure). Note that National Grid's recommendation concentrates on the target capacity alone.

Figure 15: Least Worst Regret capacities to procure compared to individual scenario/sensitivity runs



6.1.5 Covered range

A scenario or sensitivity is covered by the capacity procured if the Loss of Load Expectation (LOLE) is at or below the Government set Reliability Standard of 3 hours per year. If a scenario or sensitivity is not covered, and if one knew for certain that the scenario would occur in 2019/20, then the LOLE would be greater than 3 hours. This would increase the chances of controlled disconnection but may just result in mitigating actions (voltage reduction, max gen service and Emergency Assistance from interconnectors) being deployed more frequently/in higher volumes to avoid any controlled disconnections.

As can be seen from the above chart, procuring a capacity of 47.9 GW would result in 7 out of 18 National Grid cases (plus the DECC scenario) being covered and a capacity of 1.5 GW above target (i.e. 49.4 GW) would result in all cases being covered.

6.1.6 Adjustments to Recommended Capacity

The recommended capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State, included in the Final Auction Guidelines published after prequalification. To obtain the four year ahead (T-4) capacity auction requirement, a number of adjustments to the recommended figure or range will need to be made:

- Government upon confirming auction parameters to National Grid prior to auction guidelines will determine how much capacity to hold back/take part in year ahead (T-1) auction; primarily for DSR but not restricted to DSR – wGW

- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine DSR to opt out but remain operational - xGW
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine embedded generation to opt out but remain operational– yGW*
- Government (either upon confirming auction parameters to National Grid prior to auction guidelines or post pre-qualification) to determine large scale generation to opt out but remain operational– zGW*
- Long Term STOR contracts (currently signed) need to be excluded (pre-qualification could change this) – 0.4GW**

Therefore, the recommended total capacity to procure through the 2019/20 T-4 auction will be:

- 47.9GW-w-x-y-z-0.4GW

*National Grid's modelling assumes no generation or DSR opts out as no data is currently available to inform the modelling process but will hopefully become available through the pre-qualification process. Furthermore, as we expect DSR to be able to bid into the T-1 auction and can benefit from transitional arrangements in the meantime, this will mainly be a consideration for a T-1 auction.

** There is currently 390MW signed up under long term STOR contracts

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

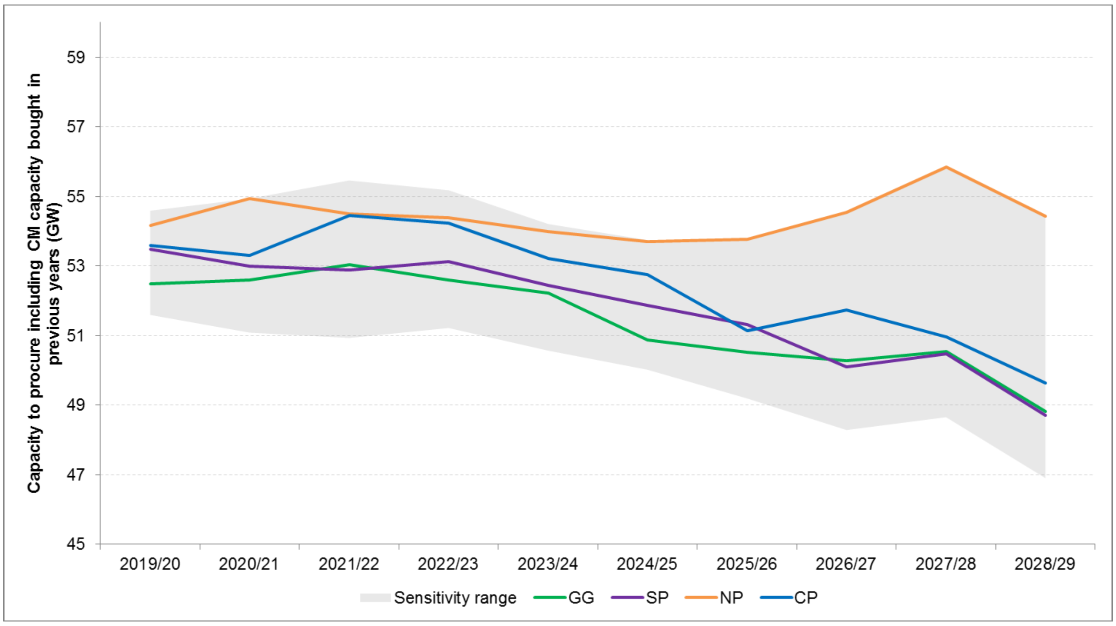
Given that it is unlikely that the marginal capacity in the auction will result in an LOLE of exactly 3 hours the auction will select a capacity from a range of ±1.5GW of the target capacity. This is represented by the shaded areas in Figure 8. Thus a recommended de-rated capacity of 47.9 GW would result in capacity (before adjustments) of between 46.4GW and 49.4GW depending on the clearing price set by the marginal capacity. The ±1.5GW tolerances are set by DECC based on the size of a typical CMU and to limit gaming opportunities. Any issues with this value can be reconciled appropriately in the T-1 auction.

6.1.7 Impact on future years

This section considers the level of capacity to procure in future years, not just 2019/20.

The No Progression scenario has a relatively stable capacity requirement whilst the remaining three scenarios show a gradual decline over the period apart from a small increase in 2027/28 when RO support for biomass conversion ends . There could be a risk of stranded assets receiving support if new capacity is built for one year and then not required in the future. However, given the current emissions regulations, in particular the Industrial Emissions Directive (IED), a number of power stations will have to close by 2023 or when they have exhausted their allocated 17,500 running hours. The current nuclear fleet will also see a number of closures over this period, due to units reaching the end of their safe operational life. These closures of existing capacity will ensure that any new capacity built in the first year of the capacity market will still be required in later years. Figure 16 shows the range in capacity to procure in future years[27] and takes account of new / refurbished capacity procured in previous years.

Figure 16: Capacity required in future years



The chart shows the level of CM capacity required to meet the Reliability Standard in all years from 2019/20. The requirement in 2018/19 was modelled in the 2014 ECR and an updated view is given in the Executive Summary. Prior to 2018/19 there isn't a similar definition of capacity so any figures would be purely illustrative and therefore potentially misleading. A separate mechanism exists (New Balancing Services[28]) to address any shortfall prior to 2018/19 that has been agreed between National Grid, Ofgem and DECC, initially for 2014/15 and 2015/16 with discussions progressing on options for 2016/17 and 2017/18. Although the requirement is calculated following exactly the same principles as laid out in this report, it is nevertheless analysed separately and the requirement is communicated via different means to this report.

6.2 Comparison with 2018/19

Last year we recommended a capacity of 53.3GW; however, this did not include any CM Agreements whereas, for 2019/20, 5.5GW of new and refurbished plant with a Capacity Market Agreement has been removed from the recommended capacity. On a comparable basis this gives a figure of 47.9+5.5=53.4GW i.e. in line with last year's headline figure as illustrated by Figure 17.

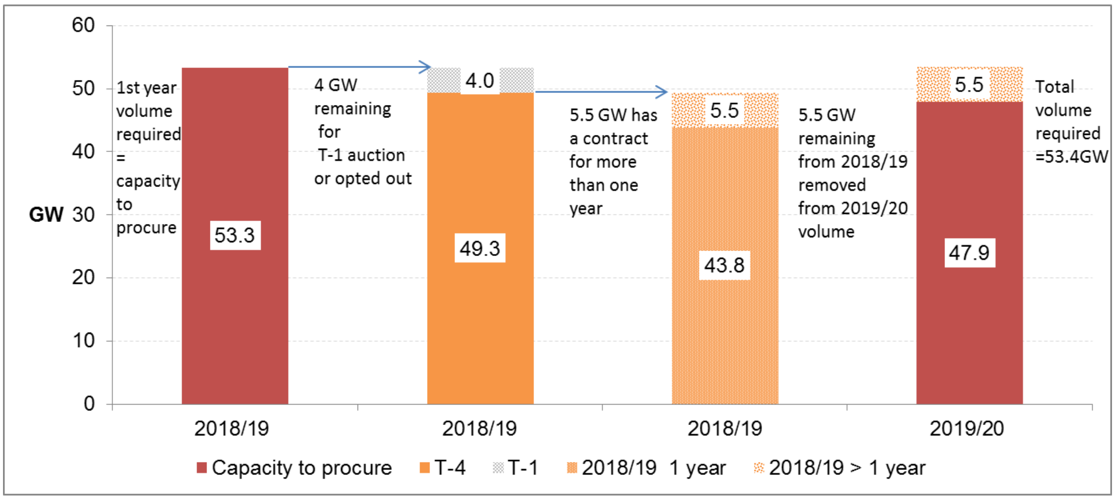
This time interconnectors can bid into the Capacity Market, whereas last year they were not – as such, the methodology accounted for it implicitly. A contribution of 0.8GW from continental Europe was assumed (net float if exports to Ireland are included). If the Secretary of State sets higher de-rating factors than those implied by

[27] Note that 2029/30 is excluded from this chart due to limitations in the way that RO supported plants have been translated from the FES into the DDM resulting in a misleading requirement in 2029/30.
[28] http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/

last year's assumption, as recommended in this report (see Chapter 7), it may result in a lower requirement for domestic capacity following the auction.

For example, in 2018/19, the requirement assumed 53.3 GW from domestic capacity and 0 GW (net) from interconnection. In 2019/20 the recommended requirement is for X GW from interconnection and 53.4 - X GW from domestic capacity (where X will be determined by the auction and the de-rating factor set by the Secretary of State).

Figure 17: Comparison with 2018/19 recommended capacity to procure



6.2.1 Comparison with 2018/19 sensitivity ranges

The following graph compares assumptions in the 2019/20 analysis runs with 2018/19. The blue bars show the range of values and the red dots show the values in the sensitivities selected by the least-worst regret analysis.

Figure 18: Sensitivity ranges compared to 2018/19 analysis

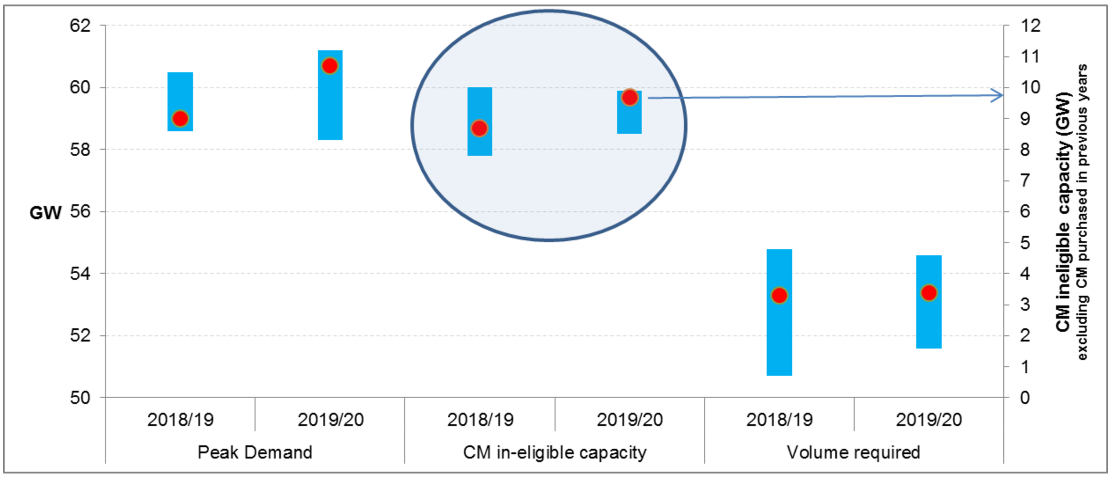


Figure 18 shows that the increase in peak demand, from 2018/19 least-worst regret sensitivity, has been substantially offset by an increase in ineligible capacity resulting in a capacity required similar to 2018/19. The CM ineligible capacity shown does not include the 5.5 GW of CM capacity purchased in 2018/19 for more than one year.

7. De-rating Factor for CM Auction

7.1 Conventional Plants

Conventional plant de-rating factors are based on the station availabilities as shown in Chapter 3 and the Annex and are updated annually as part of this process. The table below shows the proposed de-ratings factors for 2019/20 by the conventional generation technologies and includes a comparison with those used last year for the 2014 Four Year Ahead Capacity Market Auction[29].

Table 8: Conventional Plant De-rating Factors

Name for technology class	Plant Types Included	De-rating factor (2014)	De-rating factor (2015)
Oil-fired steam generators	Conventional steam generators using fuel oil	82.10%	84.61%
OCGT and reciprocating engines (non-autogeneration)	Gas turbines running in open cycle fired mode Reciprocating engines not used for autogeneration	93.61%	94.54%
Nuclear	Nuclear plants generating electricity	81.39%	82.31%
Hydro	Generating Units driven by water, other than such units: driven by tidal flows, waves, ocean currents or geothermal sources; or which form part of a Storage Facility	83.61%	84.87%
Storage	Conversion of imported electricity into a form of energy which can be stored, the storing of energy which has been converted and the re-conversion of the stored energy into electrical energy. Includes hydro Generating Units which form part of a Storage Facility (pumped storage hydro stations).	97.38%	96.63%
CCGT	Combined Cycle Gas Turbine plants	88.00%	89.00%
CHP and autogeneration *	Combined Heat and Power plants (large and small-scale) Autogeneration – including reciprocating engines burning oil or gas	90.00%	90.00%
Coal/biomass/energy from waste	Conventional steam generators using coal or biomass or waste	87.64%	87.86%
DSR		89.70%	86.80%

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

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

7.2 Interconnectors

As part of the UK's discussion with the European Commission on State Aid approval for the Capacity Market there was a commitment to include interconnectors from the 2019/20 auction onwards. The future of potential flows through interconnectors is very uncertain and as a consequence there is no one answer to the question of what can be assumed to flow through the interconnectors at times of system stress. This section outlines the various approaches National Grid, in agreement with DECC, has considered in determining an appropriate de-rating factor range for the Secretary of State to then decide the factors to apply to interconnectors in the 2019/20 T-4 auction.

7.2.1 Reasons for calculating de-rating factors

To enable interconnectors to participate in the Capacity Market auction a de-rating factor is required to convert the name plate capacity into a de-rated capacity i.e. on a similar basis to that applied to generation technologies. These de-rating factors will be for each connected country as opposed to each interconnector i.e. France will have one de-rating factor applied to each separate interconnector after allowing for an individual interconnectors technical availability (which will be determined by DECC). This process can be illustrated by the following equation:

Interconnector de-rated capacity = name plate capacity x technical availability x de-rating factor for country

Note that, as more interconnectors are connected within a country, that country's de-rating factor will fall if the generation behind the interconnector does not grow by a similar proportion or there is not enough of an existing generation surplus.

These de-rating factors will need to be reviewed annually as generation and demand changes across Europe and new interconnectors are constructed.

7.2.2 Range of analysis undertaken

Interconnector flows are the result of a complex interaction between generation and demand across Europe, subject to network constraints. Ideally this would be stochastically modelled to reflect the full range of weather, demand and generation that could occur and provide additional information such as LOLE. At the present time National Grid do not possess a suitable model or the detailed data required for this comprehensive level of analysis. Whilst steady progress is being made towards these goals for future years an interim approach has been developed for this report.

Subsequent to an initial review of potential approaches and discussions with DECC's PTE the following analysis has been undertaken to cover all the relevant uncertainties. This analysis included both commissioning consultants as well as National Grid's own background research and was signed off by DECC in February as the agreed way forward given the limitations around the availability of a European model that stochastically models the whole of Europe incorporating network constraint issues and the latest up to date generation adequacy studies in each country. Each piece of work has its own strengths and weaknesses and provides a different view to contribute to the final de-rating factors. Hence no one approach will give the answer but consideration of all of them should enable a realistic range to be identified.

Baringa – European market modelling:

Baringa has utilised their well-developed pan-European wholesale electricity model, built in PLEXOS for power systems analysis (market leading third party power market simulation software). This is a price driven model with flows driven by the prices in each country. It assumes efficient market coupling.

Power prices as calculated by the model can be composed of two components: Short Run Marginal Cost (SRMC) prices and scarcity (also known as 'uplift'). SRMC prices are based on the generation cost of the marginal generator. Uplift to prices can be applied as a function of the hourly capacity margin with the tighter the capacity margin is (during periods of low system availability and/or high demand), the higher the uplift. For this analysis, Baringa have performed cost-based modelling only (i.e. not applying uplift, even though the Baringa model is capable of applying this). Whilst uplift (and the pricing behaviour which drives this) is an important component of wholesale prices, it is a function of the market structure, which is excluded from this particular study. The data available on pricing behaviour at times of system stress is necessarily sparse and cannot be validated and where it can has been proved not to affect the results.

In order to provide insight into the likely interconnector flows at times of system stress, Baringa's pan-EU model has been enhanced to run multiple simulations (100) of the winter period (Nov-Feb). In each simulation a number of input assumptions were varied as follows:

Table 9: Baringa model input assumptions[30]

Wind output across Europe	We use historic wind output data for Europe for sampling different years for each country. Our data covers years 1970-2012 (taken from the ANEMOS wind database) – a much wider range than the demand data. Therefore, wind output and demand are not correlated.
FR and Scandinavian hydro output and FR/DE nuclear plant availability	We use different historic year samples for the French/ Scandinavian hydro output and French /German nuclear plant availability. We use the relevant historic data set from the French (RTE), German TSOs, Norwegian (Statnett) and Swedish (Svenska Kraftnät) TSOs covering the years 2008-2014 for French hydro and nuclear generation and 1996-2010 for Scandinavian hydro generation.
DE, FR and ESP solar output	We use different historic year samples for the solar output in DE, FR and ESP based on the historic data available from the TSOs of each of the three countries (RTE, German TSOs and Red Electrica) covering the period 2011-2014.
Conventional plant availability	Generator outages are simulated based on forced outage rates. Generator outages are from Baringa's propriety EU-wide generator dataset, which we are re-validating against historic availability data. GB Nuclear outages increased based on National Grid analysis of winter availability
Interconnector availability	Availability of existing Interconnectors is based on historic outage rates. For example, IFA data is from 2009-2014. For new interconnectors, data from the SKM report is used.
Demand	For each simulation, a single year is sampled from the demand data (same for all countries). Due to lack of consistent historic data (available from ENTSO-E), this selection is limited four winters (2010/11 to 2013/14) which only includes one very cold period for Europe (February 2012). The historical demand values are scaled to 2019/20 values using the ACS peak.
Commodity prices	We use different monthly seasonality for gas and coal prices based on historic price data for years 2007-2014 (taken from Platts), as well as the historical monthly average for all these years and an additional profile based on our own Baringa Reference Case assumptions.

30 The SKM report on interconnector availability figures is https://www.ofgem.gov.uk/ofgem-publications/59247/skm-report-calculating-target-availability-figures-hvdc-interconnectors.pdf

Baringa's own internal scenarios were adapted to align with the assumptions of the Future Energy Scenarios (FES) developed by National Grid.

The scenarios used National Grid's 2015 FES commodity price assumptions. The exception is the EUA carbon price which is not defined in National Grid's assumptions.

- GB capacity mixes were broadly mapped to FES 2014 (since FES 2015 was not available at the time of analysis)
- EU capacity mixes and demand were aligned to TSO forecasts for the countries of interest. Although specific reliability standards were not targeted in Baringa's modelling, an implied LOLE should be broadly consistent with respective countries' targets assuming TSO reports were consistent with these. EU capacity mixes were the same in all four scenarios.

The analysis considered the traded energy only market. Baringa's analysis did not consider the impact of reserve requirements, constraints or SO-SO agreements for example. SO-SO agreements are part of mitigating actions which fall outside this analysis.

For each hour simulated the GB capacity margin was calculated. This is the margin of available domestic supply over demand. Results are presented for different cut-off levels of GB capacity margin.

The following tables show the results for each scenario of the level of interconnector flows as a percentage of capacity at times of different domestic capacity margins[31] e.g. for SP (Slow Progression) at domestic margins below 0%, 96% of available capacity is imported from the Netherlands i.e.960MW of 1000MW capacity.

For comparison the aggregate equivalent firm capacity for interconnectors from the DDM model output ranged from 75% to 85% which is consistent with the results in the following table.

[31] Domestic GB capacity margin ranges quoted in the table are before interconnector flows are taken into consideration. If interconnector flows were included, hours below GB margin thresholds would be different (generally fewer hours except perhaps for the SEM).

Table 10: Baringa model interconnector flows

Gone Green

Capacity margin	Total hours*	GB-BE	GB- FR	GB-NL	GB-SEM
<0%	190	98%	73%	96%	-7%
<5%	1071	98%	74%	96%	-39%
<10%	3790	98%	76%	96%	-50%
<15%	9150	98%	76%	96%	-57%
<20%	17711	98%	76%	97%	-60%

Slow Progression

Capacity margin	Total hours*	GB-BE	GB- FR	GB-NL	GB-SEM
<0%	118	95%	81%	96%	2%
<5%	856	94%	80%	96%	-42%
<10%	3522	94%	80%	96%	-57%
<15%	9169	94%	78%	96%	-65%
<20%	18405	93%	77%	97%	-70%

No Progression

Capacity margin	Total hours*	GB-BE	GB- FR	GB-NL	GB-SEM
<0%	262	94%	77%	96%	5%
<5%	1570	93%	77%	96%	-29%
<10%	5845	93%	78%	96%	-43%
<15%	14126	93%	76%	97%	-48%
<20%	26977	93%	76%	97%	-50%

Consumer Power

Capacity margin	Total hours*	GB-BE	GB- FR	GB-NL	GB-SEM
<0%	7	100%	90%	100%	10%
<5%	188	96%	67%	96%	0%
<10%	1011	93%	72%	96%	-18%
<15%	3456	94%	75%	96%	-19%
<20%	8431	94%	76%	96%	-20%

*is the number of hours across the simulations when domestic margins are below % threshold

Headline messages from analysis:

Continental Europe

- Interconnectors to continental Europe are on average importing at close to maximum capacity at times of low GB capacity margin
- There is little variation in these results for different levels of GB margin
- GB generation is typically more expensive than continental Europe in ‘normal’ periods and this is carried through to tight periods

- A higher carbon price floor in GB is a major factor in the higher cost of GB generation as no uplift is included
- No unserved energy was observed in any of the model runs implying that the assumed generation capacity was larger than the level needed to meet the reliability standard in each country.

SEM (Single Electricity Market in Ireland)

- The SEM is a more complex case – typically exports are observed due to SEM peaking plant having higher generation costs than GB peaking plant. This is despite higher domestic capacity margins in SEM
- For periods of tightest GB margin, this average level of export reduces

Caveats

- Pan European model is one of the best available but has limitations associated with using it as a Monte Carlo simulation with a limited number of simulations (as opposed to full stochastic modelling), in terms of the time available to run multiple scenarios, and in the data available. For example the historic hourly demand series available on a consistent basis for EU is limited to four years of data only.
- No unserved energy was observed suggesting that the assumed generation capacity was larger than the level needed to meet the reliability standard in each country.
- In addition plant used for reserve capacity hasn't been sterilised in each country which in reality wouldn't be exported so the results will be overstated.
- Baringa have stated that their analysis should be considered as one piece of evidence alongside previous and on-going work. It represents a cost-based view of interconnector flows at times of tight GB domestic capacity margin. Therefore, it would be inappropriate to calculate de-rating factors for interconnectors from this work without wider consideration of evidence and of the limitations of this work as set out above.

Pöyry

In early 2015 DECC commissioned Pöyry to undertake analysis of potential de-rating factors (DRFs) for interconnectors with a view to producing "conservative" estimates based on historical relationships of price differentials and flows.[32]

Pöyry has identified different sets of relevant periods within a year using both tightest margin and peak demand periods within the winter quarter across the six year time series of data.

During these sets of relevant periods DRFs are calculated by counting only those periods when GB is expected to be importing electricity from an interconnector not the percentage of capacity as per Baringa.

The following methodologies were applied to count the periods contributing to the DRF of interconnectors:

- For existing interconnectors Pöyry has calculated DRFs counting those periods when; a) price differentials were positive, b) GB was importing, c) when both price differentials were positive and GB was importing.

[32] https://www.gov.uk/government/Final_historical_derating_of_IC_poyry_report.pdf

- For new interconnectors counting only those periods when price differentials were positive is applicable. These DRFs need adjustment for technical availability and transmission losses which we have not analysed, being out of scope of this work and requiring technical expert input. However, impact of alternative price differential thresholds on DRFs was analysed.
- Those interconnectors where operational data was less than the full length of analysed time series, are treated as 'new' interconnectors.

Use of highest (50%) peak demand periods in winter quarter and longer time series (>=6 years) in defining relevant periods provides conservative estimates if DRFs are calculated using:

- positive price differentials and GB imports for existing interconnectors
- positive price differentials for new interconnectors

The following table summarises the approach and results of Pöyry's analysis. It shows DRFs for France of 29%, Ireland 2%, Netherlands 62%, Belgium 58% and Norway 74%. However, note these DRFs are defined as a percentage of time that an interconnector would be available to export to GB not the expected flow.

For this analysis France and Ireland have been modelled as existing interconnectors with Netherlands, Belgium and Norway as new interconnectors. If a shorter time series is used for France i.e. 2 years compared to 6 years the DRF would be much higher at 62% due to greater price responsiveness since the introduction of market coupling.

Figure 19: Summary of approach and implied DRF

Proposed approach

Relevant periods

- 50% of peak demand periods during winter quarter
- Time series of last 6 years

Metrics

Existing interconnector: Contribution to DRF only when price differentials are positive and interconnector is importing electricity to GB

Metrics

New interconnector: Contribution to DRF when price differentials are positive

Historical de-rating factors of existing and new interconnectors

50% peak demand periods during each winter (7am – 7pm business days, 2008–2013) (2304 relevant period)

DRF calculations based on:	Interconnector from GB to:				
	France	Ireland	Netherlands[1]	Norway[1]	Belgium[1]
Price differential (+ve)	56%	17%	62%[2]	74%	58%
GB imports	36%	16%	79%[3]	-	-
Price differential (+ve) & GB imports	29%	2%	66%[3]	-	-

Interconnector to the Netherlands has a short history of performance and should be treated as a new interconnector.

NOTE: DRF of new interconnectors will need separate adjustment for technical reliability (including ramping) and a minimum positive price differential threshold to compensate transmission losses.

1 Interconnector losses set at zero as no analysis was conducted to assess them
2 DRF based on +ve price differential: 62% for April 2008 – April 2014 and 81% for April 2012 – April 2014 data
3 DRFs for the Netherlands interconnector are based on April 2012 – April 2014 data

PÖYRY

5

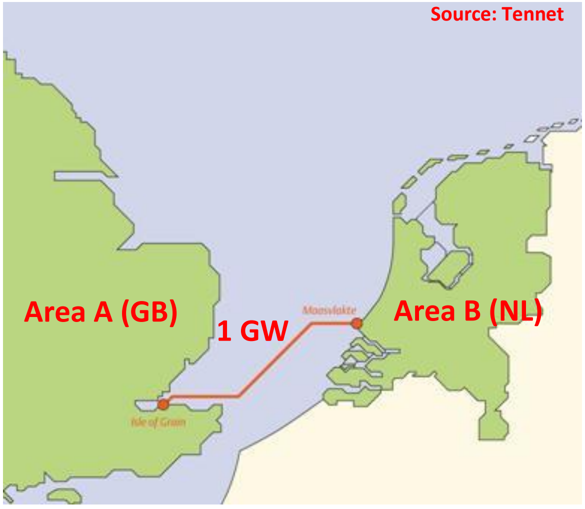
National Grid Future Energy Scenarios

The FES interconnector peak flows are based on the Pöyry analysis. For a detailed description of the approach to determining the contribution of interconnectors at peak within the FES scenarios please refer to Chapter 4.

Diversity Benefit Factor

DECC's Panel of Technical Experts (PTE) provided a suggestion to National Grid for its background research on contributions from interconnectors. This research aimed to estimate the benefits in 2019/20 through interconnection of diversity in generation outages (and to some extent diversity in demand). This suggestion considers two hypothetical countries/markets (areas A and B say) connected by a single interconnector with a generation mix that meets the reliability standard in the respective areas. For example, the "Britned" Interconnector (1 GW) connects the GB market and the Netherlands (see Figure 12 below).

Figure 20: Illustrative example of two countries / markets connected by an interconnector



Firstly a GB reference scenario was stochastically modelled that met the 3 hours LOLE reliability standard in 2019/20 and assumed no interconnection to area B. The approach (based on the PTE's suggestion) then stochastically modelled demand, generation and wind for the two areas as one to calculate a combined area LOLE value. It then imposed a constraint e.g. an interconnector between the two areas and re-ran the modelling, calculating the additional LOLE in GB due to the constraint. This was added to the combined area LOLE to estimate the GB LOLE with interconnection to area B (which was below 3 hours). The difference between this GB LOLE with interconnection and the reference case GB LOLE without interconnection was used to estimate the diversity benefit of interconnection which was expressed as a percentage of the interconnection capacity between the two areas.

This approach was used to analyse interconnection between GB (Area A) and four potential Area B's: France, the Netherlands, Belgium and the SEM (Single Electricity Market in Ireland) for the levels of interconnection assumed in 2019/20 in the FES scenarios. For these four areas, aggregate capacities and reserve assumptions were derived from the January 2020 values in Scenario B (best estimate) of ENTSO-E's

2014 Scenario Outlook & Adequacy Forecasts (SO&AF)[33]. Historical demand distributions for the four areas were largely derived from hourly load data for each area from the ENTSO-E data portal[34] . Wind distributions were created for the four areas by scaling the GB wind distribution by an appropriate ratio. De-rating factors in the four areas were assumed to be the same as GB values for technologies in common with GB and were estimated for technologies not present in GB.

The following table summarises the results showing for example a Diversity Benefit Factor for the Netherlands of 81%. Note that these figures take account of the technical availability of the interconnectors.

Table 11: Area Diversity Benefit Factors

Area	BE	BE	FR	FR	FR	NL	SEM
Scenario(s) for I/Cs	SP NP CP	GG	NP CP	SP	GG	ALL	ALL
Estimated diversity benefit factor (%)	39.0%	41.2%	36.6%	37.3%	30.0%	81.0%	55.0%

The positive diversity benefit values indicate that diversity in generation outages and demand in areas at the other end of interconnectors should bring security of supply benefits to GB. However, care should be taken when interpreting and comparing these values given the potential limitations of this analysis (see table below).

Bearing these limitations in mind, the values for France are a little lower than the other areas which may be due to the demand being more sensitive to temperature than in other countries (less surplus generation available to export in colder weather) and the timing of hourly winter peak demand in France which roughly coincides with the hourly peak winter demand in GB.

For Belgium the diversity benefit factor appears to be similar to France albeit a little higher, perhaps indicating a similar security of supply position to France in 2019/20.

For the Netherlands, the diversity benefit factor is higher at around 80% which may indicate that Netherlands has some surplus generation available to export at winter peak and may also reflect the time difference between the hourly winter peak demand in the Netherlands and in GB. In Tennet's latest monitoring report[35], LOLE values are well within the Dutch reliability standard for rest of this decade.

A recently published regional study[36] by the Pentalateral Energy Forum (PLEF) indicates some potential tightness in winter 2015/16 in France and Belgium and in France in 2020/21, but no issues in the Netherlands. This also supports the diversity benefit factors being higher for the Netherlands than France and Belgium.

For the SEM, the analysis assumes no constraints between the North and South of Ireland e.g. via the building of a North-South link by 2019/20 as assumed in Eirgrid's 2015 generation adequacy statement[37]. Given this assumption, the diversity benefit

[33] https://www.entsoe.eu/publications/system-development-reports/adequacy-forecasts/Pages/default.aspx
[34] https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx
[35] See http://www.tennet.eu/nl/fileadmin/downloads/News/Rapport/Rapport_Monitoring_Leveringszekerheid_2013-2029_TenneT.pdf (in Dutch)
[36] http://www.tennet.eu/nl/nl/nieuws/article/first-regional-generation-adequacy-assessment-report-published.html
[37] http://www.eirgrid.com/media/Eirgrid_Generation_Capacity_Statement_2015-2024.pdf

factor of 55% for the SEM indicates that there may be surplus generation available at winter peak in 2019/20 as indicated in Eirgrid's report.

The diversity benefit analysis has some advantages and disadvantages compared to the other interconnector analysis carried out. The following table summarises some key pros and cons.

Table 12: Key Pros and Cons of Diversity Benefit Analysis

Pros	Cons
It used National Grid's existing capacity adequacy stochastic model – this was the only approach using a stochastic model	Assumed no constraints within the individual areas which may have overstated the diversity benefit
It calculated the change in LOLE resulting from interconnection with four areas – this was the only approach that calculated LOLE	It took no account of flows into the four areas from the surrounding countries or between the four areas which may have understated the diversity benefits
It used a longer demand history than the Baringa analysis.	Demand history used (2005/06 to 2013/14) may not be representative of full range of weather experienced across North West Europe.
It included the impact of sterilised reserves on LOLE	Some data used for the four areas was estimated or may be out of date
It calculated the contribution of wind using EFC (consistent with ECR analysis).	It took no account of diversity in wind generation which may have understated the diversity benefit

One simplification and therefore caveat is that the analysis assumed no constraints within the individual countries which may have overstated the benefit. Conversely the analysis also took no account of flows into the four areas from the surrounding countries or between the four areas which may have understated the benefits.

Modelling of all four areas (France, SEM, Belgium and Netherlands) with GB in one assessment was attempted but was felt to overstate the results due to the over simplification of assumptions around network constraints and the fact that not all areas are physical connected.

Weather Correlation Analysis

Baringa's modelling, while being the most appropriate/robust approach, utilised a short weather/demand history data set so was exposed to that data not being representative of the weather that could occur in 2019/20. Hence to investigate the potential impact of this we undertook analysis of the correlation of weather (temperatures and wind speeds) across Europe based on the last 57 years. The weather data was purchased from Meteo Group[38].

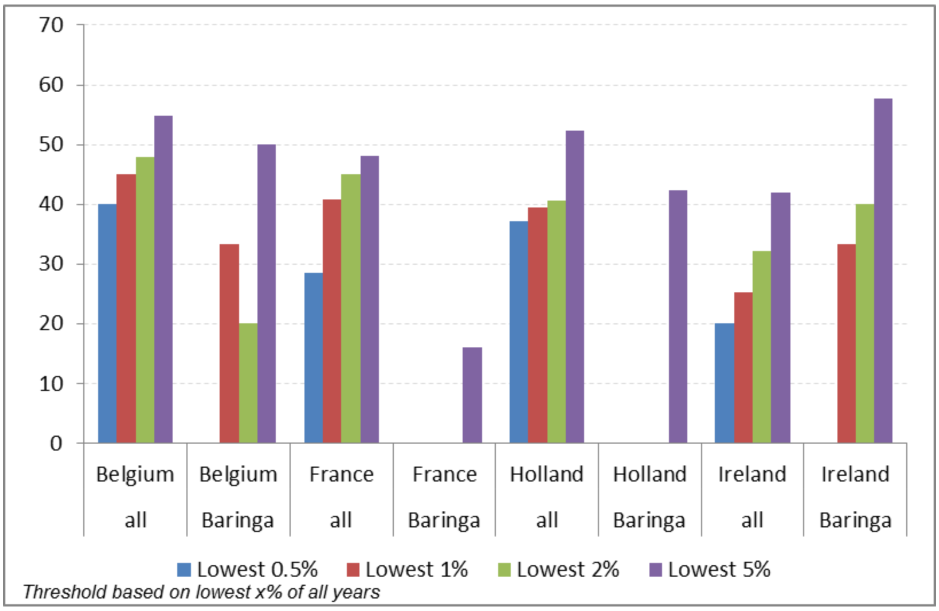
The analysis considered the evening peak period on the coldest days in London at various temperature thresholds and compared them to the coldest days in Paris, Brussels, Dublin and Amsterdam to see the co-incidence of low temperatures. For instance, when London was at or below the lowest 0.5% of coldest days there was a

[38] http://www.meteogroup.com/en/gb/services/historic-weather-data.html

40% chance that Brussels was also experiencing similar weather. This analysis was run at a number of different thresholds to check for stability.

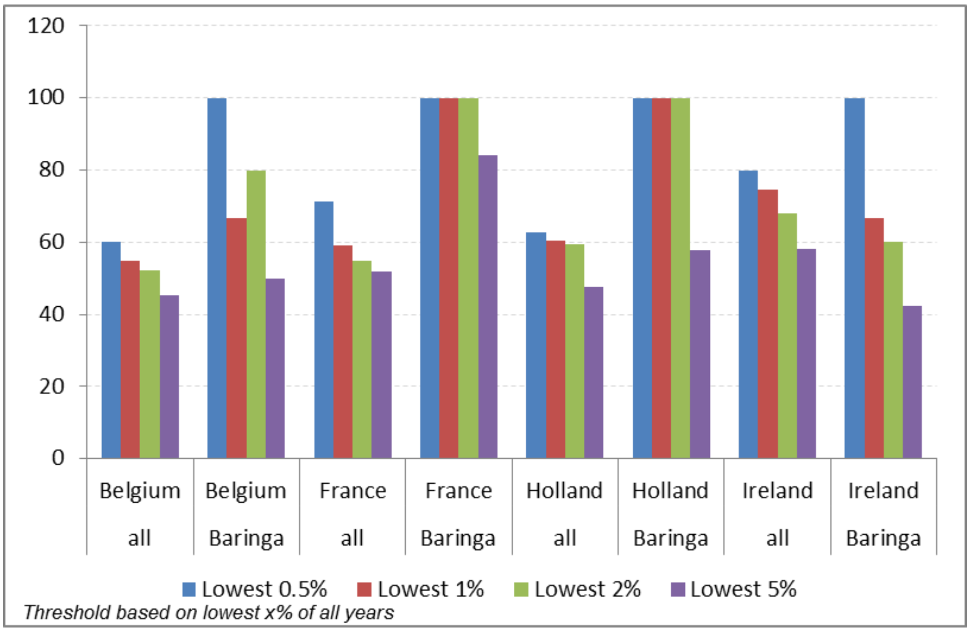
The following chart illustrates that over the last 57 years there is a reasonable level of correlation, in particular in France, that isn't incorporated within Baringa's data set and therefore assuming at such times exports are unlikely to occur it would overstate the contribution from French interconnectors.

Figure 21: Co-incidence of low temperature



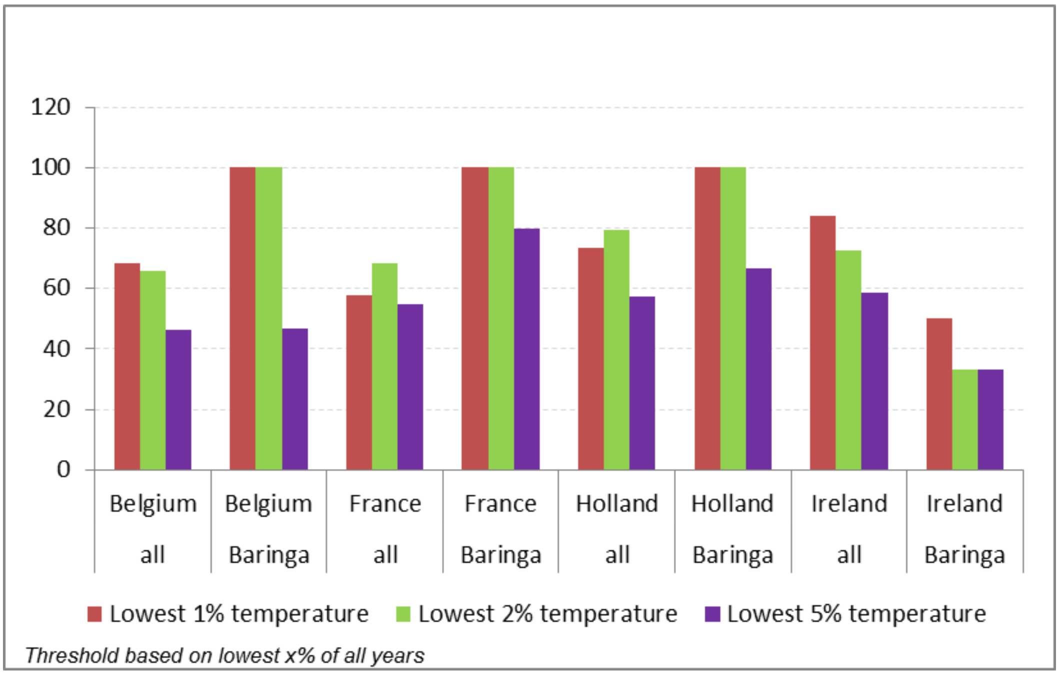
If a simplifying assumption is made that no imports or exports occur when both countries are below a threshold then the maximum percentage of time imports to GB could occur would be 100% minus the percentage of time both countries have low temperatures. We have called this number the no-correlation factor.

Figure 22: No-correlation factors based on co-incidence of low temperature



A similar exercise can be undertaken for the co-incidence of low temperatures and low wind. The following chart shows the resulting no-correlation factors, which are not surprisingly higher.

Figure 23: No-correlation factors based on co-incidence of low temperature when wind speeds are low



The advantages of this approach are the longer time series utilised that contains more severe weather events enabling a more representative analysis of the likelihood of coincidence of severe weather across Europe thus affecting potential interconnector flows between countries. However, a disadvantage is that it takes no account of the generation adequacy in each country, nor of how sensitive demand is to weather.

7.2.3 Summary of results

The following table compares the various approaches to calculating the potential contribution from interconnectors in 2019/20. Unfortunately these separate pieces of analysis aren’t all representing exactly the same thing e.g. Baringa is the percentage of the interconnector capacity while Pöyry is the percentage of time the interconnector is available to export to GB. However, until such time as European interconnectors can be modelling using a validated model with a long time series of data then these alternative approaches will have to inform the potential range of DRFs.

National Grid is on a process of incremental improvements in interconnector modelling capability with the next step being a review of commercially available network models this summer. A key element of any modelling will be obtaining appropriate data to run the model and this will also be reviewed. There is also the potential to develop some of these interim approaches should a full network model be a step too far for next year. For example, the weather coincidence analysis could be developed to include temperature/demand and wind generation/wind models to more accurately reflect the impact of weather on capacity margins.

Table 13: Comparison of Results

Country	Baringa (below 0% GB margin)	Pöyry	FES	Diversity Benefit Factor	Weather (temperature)	Weather (temperature and wind)
France	73-90%	29% * (62%)**	43-52%	35%	52%-71%	55%-68%
Netherlands	96-100%	<62% (81%)***	59%	81%	48%-63%	58%-80%
Belgium	94-100%	<58%	55%	40%	45%-60%	46%-68%
SEM (Ireland)	Exports to 10%	2%	0%	55%	58%-80%	58%-84%

- For Baringa, FES and Diversity Benefit the percentages refer to the flow as a percentage of capacity i.e. Baringa's modelling gives a range from 96% (960MW) to 100% (1000MW) for the Netherlands.

- For Pöyry and Weather the percentages refer to time when interconnectors are available to import

*29% based on 6 years data (2008-2013)
**62% based on most recent market coupled years (2012-2013)
*** 81% based on market coupled years (2012 – 2014)

As mentioned above there are a number of differences between the analysis along with strengths and weaknesses which can be summarised as follows:

Table 14: Comparison of methods for estimating de-rating factors

	Baringa	Pöyry	FES	Diversity Benefit	Weather
Time or flow based	Flow	Time	Both	Flow	Time
History or future	Future	History	History	Future	History
Includes technical de-rating	✓	mixed	✓	✓	×
Stochastic	✓	×	×	✓	×
Long temperature/demand history	×	×	×	medium	✓
Long wind speed history	medium	×	×	GB only	✓
FES price assumptions	✓	×	×	×	×
FES generation capacities	GB mapped to 2014 FES	×	×	Based on 2014	×
FES interconnector capacities	✓	×	×	✓	×

Hence in deciding a realistic potential range for de-rating factors for interconnectors care has to be taken as no one approach is robust enough to stand alone and thus a degree of judgement is required.

7.2.4 Potential range for interconnector de-rating factors

DECC has requested a range for each connected country to enable the Secretary of State to decide the DRFs with advice from the PTE.

We recommend that the de-rating factors for interconnectors in 2019/20 should be a round number towards the conservative end of the range.

- This balances the risks to consumers of non-delivery against the de-rating factor and cost of capacity
- If, following additional evidence and more detailed modelling, the de-rating factor is found to be too high then there is a risk of unsuccessful generation closing and not being available for the T-1 auction.
- If the de-rating factor is too low then an adjustment can be made in subsequent years by buying less in the T-1 auction.

As more information becomes available, combined with enhanced modelling, we will be able to narrow the range with confidence.

Connected Countries Ranges:

Due to the uncertainties around this process as highlighted by the wide range of results from the different pieces of analysis undertaken there can be no definitive answer so National Grid has, as requested by DECC, provided a realistic recommended range for each connected country as set out below. For all countries (except France), the Pöyry de-rating factor (DRF) sets the bottom of the range as this is the minimum bottom-stop DRF that will be allocated to each country. For France, the bottom of range is aligned to a higher value than Pöyry as the Pöyry DRF was largely based on a period before market coupling. The top of the range was set at or below the Baringa range as the Baringa analysis may have underestimated the coincidence of cold weather (and made no allowance for sterilisation of reserves).

France 50-70%

- The evidence for French de-rating factors is highly variable with the lowest being 29% and the highest 90%. The Pöyry analysis shows that de-rating factors have significantly improved since market coupling although this period was generally mild. At the top of the range, the 90% figure from Baringa is an outlier based on only 7 hours in the Consumer Power scenario with the next highest being 81% from the Slow Progression scenario. RTE reports that France needs significant imports when demand is high and as French demand is very weather sensitive, greater emphasis has been put on the weather no-correlation factors.
- Top of the range roughly matches the top of the weather range as well as the bottom of the Baringa range since French demand is very weather sensitive and the weather analysis shows that the Baringa modelling may have under estimated the coincidence of cold periods.
- Bottom of the range roughly matches the bottom of the weather range as well as aligning with the top of the FES range. This is higher than the bottom stop Pöyry DRF of 29% which was largely based on a period prior to market coupling.

Netherlands 62-80%

- Top of the range consistent with the top of the weather range, the Pöyry figure for market coupled years as well as the Diversity Benefit factor. Higher figures from Baringa modelling are supported by an apparent surplus in Netherlands generation (indicated by recent reports – see diversity benefit analysis section) but weather analysis shows that the Baringa modelling may have under-estimated coincidence of cold weather.

- Pöyry figure sets bottom of the range.

Belgium 58-70%

- Top of the range consistent with the top of the weather range. Baringa's analysis shows similar range for Belgium to the Netherlands but weather analysis shows it is more closely aligned to France for weather and wind correlation.
- Pöyry figure sets bottom of the range.

SEM 2-10%

- Top of range consistent with top of Baringa's analysis range. Generation diversity has higher range as there appears to be surplus generation available in the South of Ireland but this assumes no constraints exist between the North and South of Ireland (consistent with Eirgrid's analysis). However if constraints still exist in 2019/20, any exports from the South of Ireland to GB at times of system stress may well be offset by exports from GB to the North of Ireland. Hence we have not used the diversity benefit analysis in setting the range.
- Imports via Moyle are currently limited to 80 MW and there are no plans to increase this because of the network reinforcement required.
- Pöyry figure sets bottom of the range.

<u>How could the Secretary of State select one figure for each country and interconnector?</u>

In deciding what level of DRFs to apply to interconnectors the Secretary of State could consider the following:

- As there is currently no clear metric for deciding we would suggest that initially a lower figure is set which can then be increased over time as imports are proven.
- What level of risk is acceptable e.g. the higher the DRF the higher the risk associated with the consequences if it fails to deliver as expected/contracted.
- What are the cost implications within the auction of low/high DRFs for interconnectors e.g. if DRFs are low more plant capacity would be needed to meet the standard and if this is more costly in the auction then overall costs to consumers will rise.
- A least worst regret approach could potentially be used to inform the selection of a de-rating factor for each area from among the range of suggested values. For example, regret costs for potential de-rating factors could be calculated against potential levels of outturn imports in 2019/20. For an outturn level below a potential de-rating factor level the unserved energy costs will increase (these can be estimated using the unserved energy data output from the DDM for a range of scenarios multiplied by the VoLL) offset by a reduction in capacity costs assuming the shortfall in imports is not made up by other contracted CM participants. The change in capacity payments can be estimated using an assumed 2019/20 T-4 auction clearing price (either net CONE or an indicative value obtained from an average modelled DDM output supply curve. Note that the modelled supply curves within the DDM should be treated as indicative only since, for example, the cost data utilised in the

modelling is not station specific and may be out of date as it is based on the EMR Delivery Plan published in 2013). For an outturn import level above a potential de-rating factor level the unserved energy cost will reduce, but the capacity costs will remain the same. Note that this LWR approach does not take account of any change in other costs e.g. wholesale prices resulting from any change in the level of imports.

- If any further evidence on interconnection DRFs comes forward between now and 2019/20, the T-1 auction requirement could be adjusted to take account of any difference between the new view on DRFs and the interconnection DRFs used in the T-4 auction.
- Differences between interconnectors from the same country should be based around technical availability. However, as the number of interconnectors increase from the same country then DRFs should fall unless there is a similar increase in the capacity available “behind the interconnector”.

In summary there is no clear way to determine the exact level to assume for DRFs for each connected country and interconnector; however, we can support DECC and DECC’s PTE in advising the Secretary of State on this decision, for example, by providing DDM output data such as generation cost curves.

8. Annex

8.1 Future Energy Scenario Assumptions

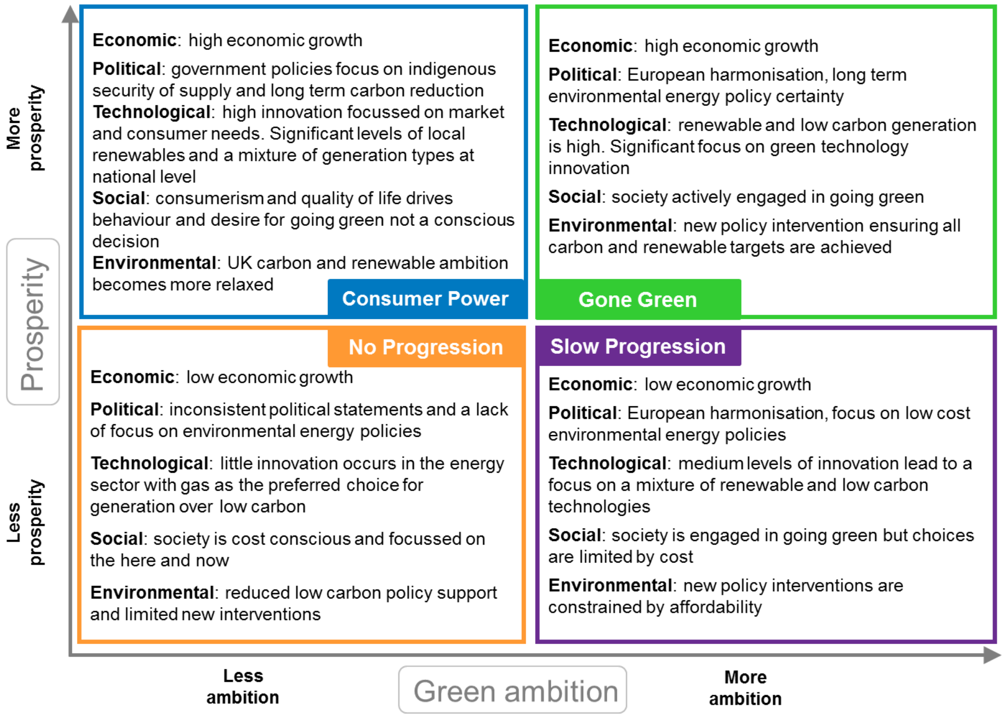
Our scenarios are used as a reference point for a range of modelling activities. Importantly, they are used for network analysis that enables National Grid to identify potential gas and electricity network investment requirements in the future, as highlighted in the Gas and Electricity Ten Year Statements (GTYS and ETYS). Security of supply analysis has also become an important use for our scenarios.

Stakeholders' views were positive regarding our 2014 FES in terms of scope, content, process and delivery. We were told there was no requirement for radical changes so we have adopted an "evolutionary" approach to the development of our 2015 FES. They represent a logical progression from last year with improvements and revisions based on stakeholders' feedback.

We have continued to base our 2015 scenarios around the energy trilemma, in response to strong positive feedback from our stakeholders who felt it provided a common narrative for engagement across the energy industry. We will continue to flex sustainability and affordability. All four scenarios will continue to meet the Reliability Standard, which is in line with one of the key objectives of Electricity Market Reform.

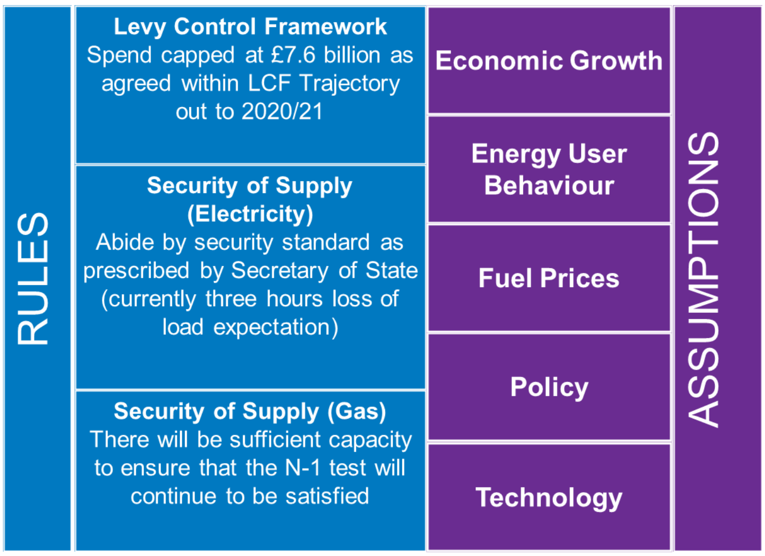
One of the top feedback themes on FES 2014 was lack of clarity on the scenario axes. In response National Grid has moved from an 'affordability' axis to 'prosperity'. This better reflects that this axis looks at how much money is available at a Government, consumer and business level for investment. This may be in terms of money being available for Government support for renewable generation, businesses having money to invest in new energy efficiency measures, or consumers having money to spend on new technologies such as electric vehicles. The 'green ambition' axis represents the importance that politicians place on going green in policy making based on how the focus changes in relation to today's position. Using electricity generation as an example, a high green ambition scenario is likely to have policies to drive high levels of renewable and low carbon generation.

Figure 24: FES Scenarios



The primary assumptions and rules drive the modelling in the scenarios, and replace the previous axioms. Many of their stakeholders found 26 axioms too many and difficult to understand with no hierarchy or structure. Having five high level assumptions will provide clarity to the FES readers into what underpins the scenarios.

Figure 25: Primary Assumptions



8.2 Detailed Modelling Assumptions

The following describes in more detail the modelling assumptions outlined in Chapter 3. National Grid provides the details of the key inputs for the DDM model. All other input assumptions for the DDM are as EMR Scenario 1 from the EMR Delivery Plan.

8.2.1 Demand (annual and peak)

The annual and peak demand used for the 4 FES scenarios covering the next 15 years. All sensitivities use the same annual and peak demand as their corresponding scenario.

Table 15: Annual demand by scenario**

Annual Demand TWh	2015	2016	2017	2018	2019	2020	2021	2022
Gone Green	336	335	332	330	329	330	331	334
Slow Progression	338	337	337	336	335	335	334	333
No Progression	339	339	339	337	336	334	333	332
Consumer Power	339	336	335	335	334	334	334	335

Annual Demand TWh	2023	2024	2025	2026	2027	2028	2029	2030
Gone Green	337	340	343	347	352	356	361	365
Slow Progression	333	332	332	332	332	332	333	332
No Progression	331	331	331	331	331	332	332	333
Consumer Power	334	335	336	337	338	340	342	342

**The definition of annual demand is GB National Demand plus demand supplied by embedded generation

Table 16: Peak demand by scenario**

Peak Demand GW	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Gone Green	60.5	59.7	59.4	59.2	59.3	59.7	60.2	61.1
Slow Progression	60.5	60.4	60.3	60.3	60.3	60.2	60.1	60
No Progression	60.4	60.7	60.7	60.6	60.5	60.4	60.3	60.3
Consumer Power	60.7	60.4	60.4	60.5	60.7	60.9	61.2	61.5

Peak Demand GW	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Gone Green	61.8	62.5	63.1	63.9	64.7	65.4	61.1
Slow Progression	59.9	59.9	59.9	59.7	59.7	59.5	60.0
No Progression	60.2	60.3	60.5	60.5	60.7	60.8	60.3
Consumer Power	61.5	61.7	61.9	62	62.3	62.5	61.5

**The definition of peak demand is unrestricted GB National Demand plus demand supplied by embedded generation

8.2.2 Generation Mix

The Generation mix for the 4 FES scenarios from the DDM model:

Table 17: Gone Green generation mix

Gone Green Generation Mix (GW)	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
CM eligible	65.9	63.8	64.3	63.2	60.0	60.0	60.5	60.9
Non-CM	17.5	19.6	22.3	24.8	27.1	29.2	33.9	40.9
Total peak capacity	83.4	83.4	86.7	88.0	87.0	89.2	94.4	101.7

Gone Green Generation Mix (GW)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
CM eligible	61.7	59.3	57.8	57.2	57.2	55.4	59.7
Non-CM	51.6	54.9	59.3	59.9	63.2	67.3	72.8
Total peak capacity	113.3	114.3	117.1	117.1	120.4	122.7	132.5

Table 18: Slow Progression generation mix

Slow Progression Generation Mix (GW)	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
CM eligible	65.9	63.5	64.7	64.6	61.4	60.8	60.4	60.6
Non-CM	17.6	19.6	21.3	24.3	25.8	27.2	28.8	32.2
Total peak capacity	83.5	83.1	86.0	88.9	87.2	88.1	89.2	92.8

Slow Progression Generation Mix (GW)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
CM eligible	61.7	59.3	57.8	57.2	57.2	55.4	59.7
Non-CM	45.6	51.6	54.9	59.3	59.9	63.2	67.3
Total peak capacity	107.3	110.9	112.7	116.5	117.1	118.6	127.0

Table 19: No Progression generation mix

No Progression Generation Mix (GW)	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
CM eligible	66.8	63.8	66.1	65.7	62.9	63.2	62.5	62.0
Non-CM	17.3	18.8	20.7	22.7	24.0	25.2	26.6	26.8
Total peak capacity	84.1	82.6	86.8	88.4	86.9	88.4	89.1	88.8

No Progression Generation Mix (GW)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
CM eligible	61.2	60.4	60.3	61.1	62.9	61.1	61.2
Non-CM	27.8	30.3	31.3	32.3	30.6	32.6	32.8
Total peak capacity	89.0	90.7	91.6	93.4	93.5	93.8	94.0

Table 20: Consumer Power generation mix

Consumer Power Generation Mix (GW)	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
CM eligible	65.9	65.0	65.8	64.2	61.1	60.6	61.9	61.2
Non-CM	17.8	19.6	22.8	24.7	26.9	28.9	29.5	31.7
Total peak capacity	83.7	84.6	88.6	88.9	88.0	89.5	91.3	92.9

Consumer Power Generation Mix (GW)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
CM eligible	59.6	58.9	56.6	56.9	56.2	54.7	54.8
Non-CM	34.7	38.2	40.9	41.5	43.1	45.0	45.6
Total peak capacity	94.3	97.1	97.5	98.4	99.2	99.6	100.4

8.2.3 Capacity already procured

Table 21: Capacity already procured[39] for 2019-20 in 2018-19 T-4 Auction

Plant Type	Capacity already procured (GW)
New Plants (14 and 15 years agreement)	2.4
Refurbished Plants (3 years agreement)	3.1
Total	5.5

8.2.4 Station Availabilities

The station availabilities used for the 4 FES scenarios, the Base assumption, the DECC Scenario and the High and Low availability sensitivities (rounded to the

[39] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202014%20Final%20Auction%20Results%20Report.pdf

nearest %). Note the two sensitivities cover the two most uncertain technologies of CCGT and Nuclear.

Table 22: Station availabilities by sensitivity

Generation Type	Base	High Availability	Low Availability
CCGT Pre 2018	**87%**	**89%**	**85%**
CCGT 2018/19	**88%**	**90%**	**86%**
CCGT 2019/20	**89%**	**91%**	**87%**
CCGT 2020/21	**90%**	**92%**	**88%**
CCGT post 2021	**90%**	**92%**	**88%**
Coal	88%	88%	88%
Nuclear (Existing)	**82%**	**89%**	**76%**
Nuclear (New)	**90%**	**90%**	**90%**
ACT Advanced	88%	88%	88%
ACT CHP	88%	88%	88%
ACT Standard	88%	88%	88%
AD	88%	88%	88%
AD CHP	88%	88%	88%
Autogeneration	90%	90%	90%
Biomass CHP	88%	88%	88%
Biomass Conversion	88%	88%	88%
Coal CCS	88%	88%	88%
CHP (large scale)	As CCGT	As CCGT	As CCGT
Dedicated Biomass	88%	88%	88%
EfW	88%	88%	88%
EfW CHP	88%	88%	88%
Gas CCS	88%	91%	87%
Gas Turbine	95%	95%	95%
Geothermal	88%	88%	88%
Geothermal CHP	88%	88%	88%
Hydro	85%	85%	85%
Landfill	88%	88%	88%
OCGT	95%	95%	95%
Oil	85%	85%	85%
Pumped storage	97%	97%	97%
Sewage Gas	88%	88%	88%
Solar PV	0%	0%	0%
Tidal	22%	22%	22%
Wave	22%	22%	22%

Note: that the High and Low Availability only adjust CCGTs and nuclear as shown above in bold.

8.2.5 Reserve to cover largest infeed loss

National Grid has to hold capacity in order to maintain system operability if a loss of generating capacity occurs. This capacity has to be accounted for in the LOLE calculation and is added to the peak demand assumptions. Note that infeed loss increases as new plants connect to the network, requiring a higher level to be held.

Table 23: Reserve to cover largest infeed loss by scenario

In Feed Loss MW	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Gone Green	900	900	900	900	900	1200	2100	2100
Slow Progression	900	900	900	900	900	900	1200	2100
No Progression	900	900	900	900	900	2100	2100	2100
Consumer Power	900	900	900	900	900	900	2100	2100

In Feed Loss MW	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Gone Green	2000	2000	2000	2000	2000	2000	2000
Slow Progression	2100	2100	2100	2100	2100	2100	2100
No Progression	2100	2100	2100	2100	2100	2100	2100
Consumer Power	2100	2100	2100	2100	2100	2100	2100

Note that the largest infeed loss above is not included in the peak demand values shown in Table 7.

8.2.6 Least Worst Regret

The following have been used in the Least Worst Regret calculations. The assumption for the Value of Lost Load (VoLL) is 17,000 £/MWh. The assumptions for the cost of capacity are (in 2012 prices):

- 25,000 £/MW/yr the cap in Capacity Market auction for a price taker
- 49,000 £/MW/yr the net CONE for a new CCGT
- 75,000 £/MW/yr the Capacity Market auction cap

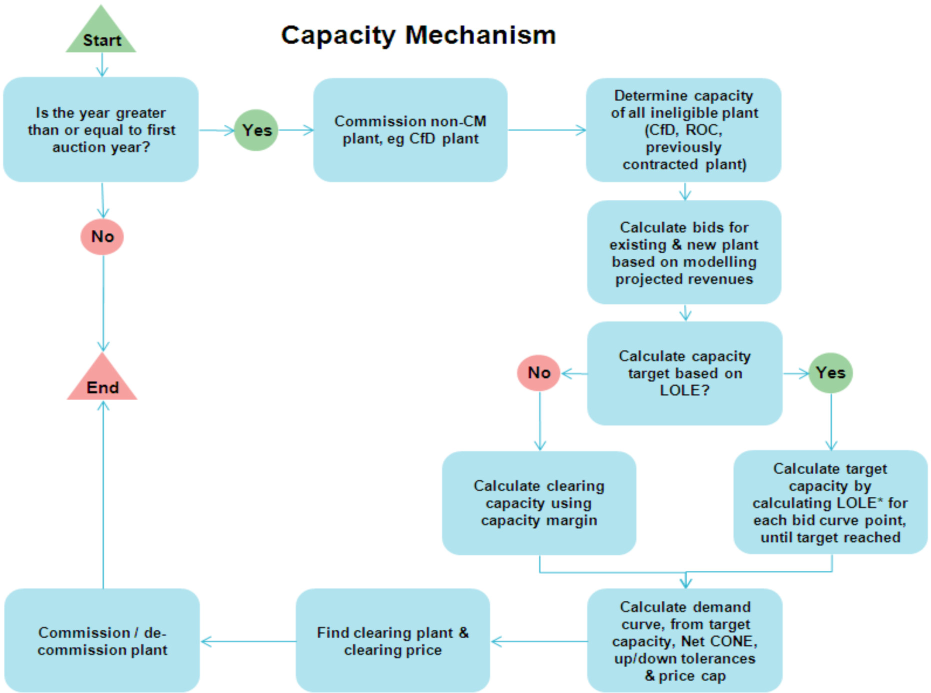
8.3 Detailed Modelling Approach

The following describes in more detail the modelling approach used in this report, this expands on Chapter 3.1 and Chapter 3.3.

8.3.1 Using DDM to model capacity to procure

The DDM models the Capacity Market and how this is used to determine the capacity to procure. This describes the detail behind the high level diagram shown in Chapter 4 and also below:

Figure 26: Capacity Market flow chart[40]



- The model first determines whether an auction should be run, this is decided if the current year is greater than the first year allowed for a Capacity Market auction of 2015 for delivery in 2019/20. The model assumes that an auction is run is all subsequent years from 2015.

- As described in Chapter 3.2 generation (including demand side response) can be split into capacity that is eligible for the Capacity Market and capacity that is not eligible for the Capacity Market. All of the non-eligible capacity is included as this plant is determined by the underlying scenario. The stochastically modelled contribution of interconnection is included in the eligible capacity.

- All of the non-eligible capacity has its capacity calculated, which may include plants that have a Capacity Market agreement longer than a year. This capacity will be accounted for before any Capacity Market auction is run.

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

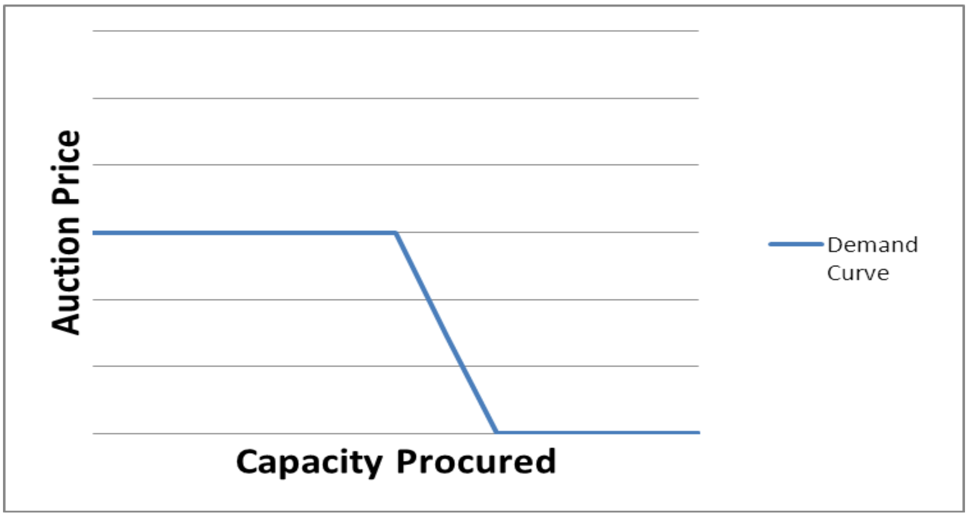
- All existing and potential new capacity is ranked by their bids into the auction based on modelled revenues and expenditure. Interconnection is assumed to bid in at zero since the DDM does not model the economics of generation in interconnected countries.

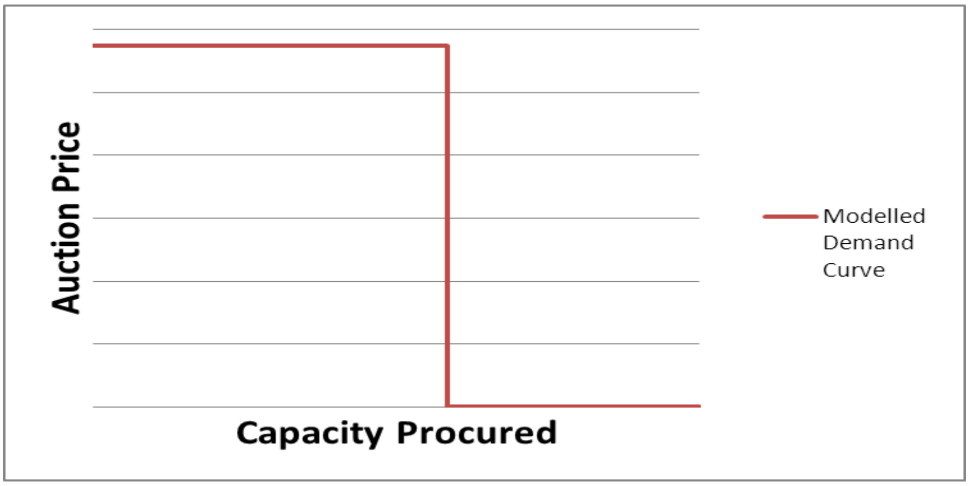
- The model has the option to target either an LOLE or a capacity margin. For this analysis a target LOLE of 3 hours is used.

- The model then assesses the LOLE associated with each increasing bid in the Capacity Market auction. The capacity not eligible for the Capacity Market auction is accounted for first. The model calculates LOLE by stochastically modelling conventional generation using its availability e.g. if a plant has 90% availability then in 90% of the simulations that plant will be available to generate at its full capacity. For interconnection, the expected contribution is determined by stochastic modelling using around a set of flow distributions obtained from Baringa's pan European model. For wind capacity the generation is determined from sampling a history of wind speeds. There is loss of load if demand exceeds available generation. The demand is determined by the input peak demand and this is used to scale a historic demand curve.

- Under normal running the model will use an auction demand curve (illustrated in Figure 27a), which will allow the model to determine a level of capacity taking into account the cost of capacity which enters the auction. For this analysis, the capacity to procure has to hit exactly 3 hours LOLE, so the demand curve has been altered in order to hit exactly 3 hours LOLE and not be allowed to procure more or less capacity (illustrated in Figure 27b). Also the auction cap has been raised well above the 75 £/KW so this allows the model to build the capacity required:

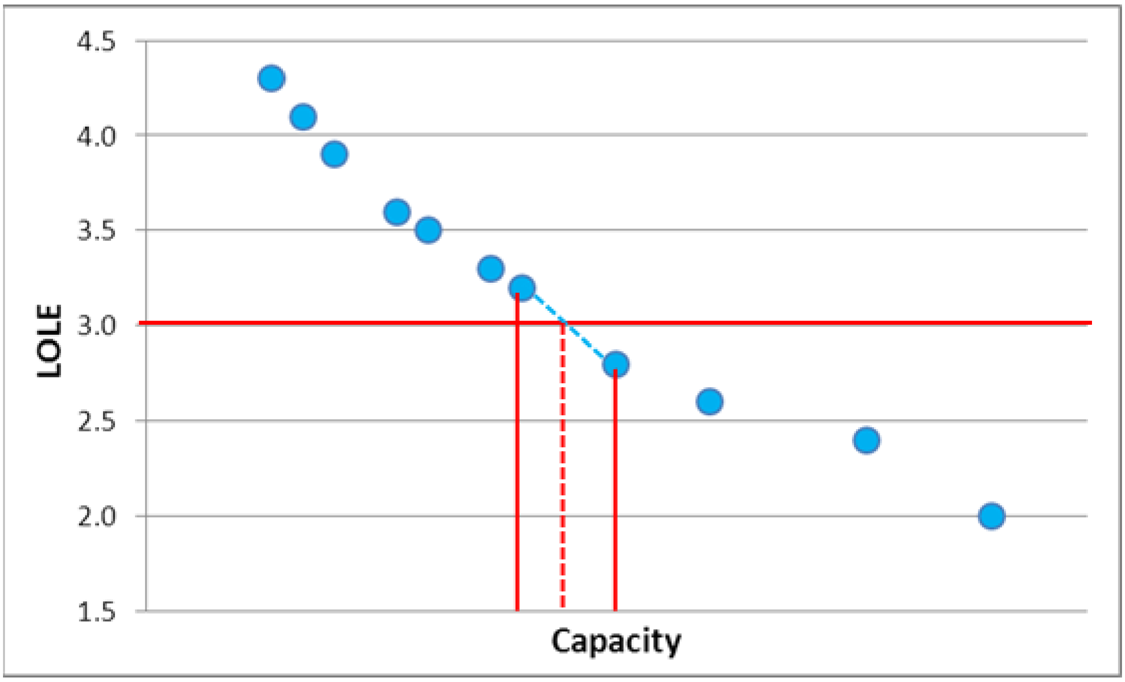
Figure 27: a) Pre and b) Post Modelling Demand Curve





- Given the model has to hit the 3 hours LOLE by using a combination of new and existing plants and demand side response and these plants are specific capacities it is unlikely that the LOLE will be exactly 3 hours. In order to compensate for this the model also interpolates between the two marginal plants around 3 hours LOLE to determine the exact capacity to hit 3 hours LOLE as illustrated in Figure 28:

Figure 28: Model interpolation to achieve 3 hours LOLE



This capacity is reported for each year modelled from 2018/19 to 2029/30 and is split as follows:

- Total de-rated capacity required to hit 3 hours LOLE
- De-rated capacity to procure in the Capacity Market auction
- De-rated capacity expected to be delivered outside the Capacity Market auction
- Total nameplate capacity split by CM and non-CM eligible technologies.

8.3.2 Treatment of Generation Technologies

The DDM models a range of generation technology types. For this analysis they are the same categories which were modelled in the EMR Delivery Plan. Most of these technologies are assumed to either be eligible for the Capacity Market or not. Hydro capacity is split between both categories. Section 3.2 describes how this split is determined. Below is a table of generation technologies modelled and whether they are assumed to be Capacity Market eligible or not:

Table 24: Capacity market classification of generation capacities

Type	Capacity Market Eligible	Outside of Capacity Market
CCGT	✓	
Coal	✓	
Nuclear (Existing)	✓	
Nuclear (New)		✓
Onshore Wind		✓
Offshore Wind		✓
ACT Advanced		✓
ACT CHP		✓
ACT Standard		✓
AD		✓
AD CHP		✓
Biomass CHP		✓
Biomass Conversion		✓
Coal CCS		✓
CHP	✓	
Dedicated Biomass[41]	✓	
EfW	✓	
EfW CHP		✓
Gas CCS		✓
Gas Turbine	✓	
Geothermal		✓
Geothermal CHP		✓
Hydro	✓	✓
Landfill		✓
OCGT	✓	
Oil	✓	
Pumped storage	✓	
Sewage Gas		✓
Solar PV		✓
Tidal		✓
Wave		✓

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

For a technology receiving support, the technology is eligible for the Capacity Market when this support has finished. Any capacity under 2 MW is also not eligible for the Capacity Market. If a technology is not eligible for the Capacity Market, then any capacity of that type under 2 MW is automatically not eligible for the Capacity Market. Any generation capacity that is under a total capacity of 2 MW is not eligible for the Capacity Market. The unsupported generation capacity that is under 2 MW has been estimated by National Grid to range from 0.6GW to 1GW by 2019/20 depending on the FES scenario.

8.4 Least Worst Regret

8.4.1 Approach

Chapter 5 gives an overview of the process used to determine the recommended capacity to procure which utilises a Least Worst Regret approach.

When deciding on an option, the Least Worst Regret approach aims to minimise the cost implications of any decision made when there is uncertainty over the future. One benefit of this approach is that it is independent of the probabilities of the various potential future outcomes and therefore it can be used when the probabilities of these outcomes are unknown, providing that the cases considered cover a range of credible outcomes. This approach has been endorsed by DECC's PTE and was supported at the National Grid Industry Implementation Workshop last year, as being the most appropriate way of choosing the recommended de-rated capacity. It accounts for the cost of procuring capacity and the cost of loss of load events (i.e. cost of unserved energy). There was general agreement that the unit costs used in the approach should be supplied by DECC based on public domain information.

The approach involves considering each potential de-rated capacity choice (i.e. the required level to ensure it meets 3 hours LOLE) derived from a particular outcome (scenario or sensitivity) and assessing the cost of the other potential outcomes under that capacity choice to find the maximum regret cost for that potential choice. In other words, if a particular de-rated capacity level is chosen then this approach assesses the worst outcome (arising from under or over procurement) that can be expected if a different scenario or sensitivity occurs in future. To do this, a base cost for that case is calculated as the cost associated with the required level of de-rated capacity. For the other outcome cases assessed against that de-rated capacity choice, the regret cost is defined as the absolute value of the difference between the total cost and the base cost. The maximum regret cost for a potential de-rated capacity level is then calculated as the highest of the regret costs across all cases, i.e. the highest cost difference arising from over or under procurement.

This process is repeated for each potential de-rated capacity choice to find the minimum of the maximum regret costs over all potential choices derived from all scenarios and sensitivities. The Least Worst Regret option is the potential de-rated capacity level with the minimum of the maximum regret costs. This is the same principle used in National Grid's National Development Policy to choose between potential transmission network reinforcement options[42]. This approach has also been used to assess the volume required for National Grid's new balancing services[43] in 2014/15 and 2015/16.

In order to determine the maximum regret cost for a particular case, a view on the unit de-rated capacity cost and unit cost of unserved energy is required. Costs obtained directly from the modelling have not been used; furthermore, the auction process itself will determine the outturn costs.

[42] See http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/

For the analysis, the following is used; VoLL (Value of Lost Load) = 17,000 £/MWh as the unit cost of Expected Energy Unserved (EEU) and net CONE (cost of new entry) = 49,000 £/MW/year[44] as the unit cost of de-rated capacity.

The total cost of a case (scenario or sensitivity) is calculated as:

Total Cost = Cost of De-Rated Capacity to Procure + Cost of EEU

where:

Cost of De-Rated Capacity to Procure = De-Rated Capacity Procured (MW) * Unit cost of De-Rated Capacity (£/MW)

and:

Cost of EEU = EEU (MWh) * Unit Cost of Unserved Energy (£/MWh)

The cost of the 5.5 GW of capacity already procured for 2019/20 in the 2018/19 T-4 auction is excluded from the above calculation as it is the same cost for all scenarios and sensitivities and has no impact on the Least Worst Regret calculation.

8.4.2 Worked Example

Below is a worked example, taken from the 2014 ECR analysis but the process is no different this year, this is based only on the 2014 FES capacities to procure and shows how the Least Worst Regret will determine a recommended capacity to procure:

1. The capacities which each scenario looks to procure are shown below:

Table 25: Capacity to procure by scenario

Scenario	Capacity to procure (de-rated) MW
Gone Green	51,358
Slow Progression	52,975
No Progression	53,887
Low Carbon Life	53,962

2. The cost of capacity is assumed to be 49,000 £/MW/yr, this represents the net CONE of a new CCGT. The costs of procuring the scenario capacities are show below:

[44] As outlined in the EMR Stakeholder bulletin issued on May 14th 2014

Table 26: Cost of capacity by scenario

Scenario	Capacity to procure cost £m
Gone Green	2,517
Slow Progression	2,596
No Progression	2,640
Low Carbon Life	2,644

3. The EEU for each scenario depends on the scenario and capacity procured. The table below shows EEU is for the combinations of scenarios:

Table 27: EEU by scenario combination

Scenario	Procure Gone Green MWh	Procure Slow Progression MWh	Procure No Progression MWh	Procure Low Carbon Life MWh
Gone Green	4,437	1,280	568	514
Slow Progression	13,009	4,405	2,168	1,993
No Progression	23,284	8,309	4,274	4,011
Low Carbon Life	24,188	8,840	4,795	4,406

4. Costs of EEU is 17,000 £/MWh. The table below shows the cost of EEU is for the combinations of scenarios:

Table 28: Cost of EEU by scenario combination

Scenario	Procure Gone Green £m	Procure Slow Progression £m	Procure No Progression £m	Procure Low Carbon Life £m
Gone Green	75	22	10	9
Slow Progression	221	75	37	34
No Progression	396	141	73	68
Low Carbon Life	411	150	82	75

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

Table 29: Total cost by scenario combination

Scenario	Procure Gone Green £m	Procure Slow Progression £m	Procure No Progression £m	Procure Low Carbon Life £m
Gone Green	2,592	2,618	2,650	2,653
Slow Progression	2,738	2,671	2,677	2,678
No Progression	2,912	2,737	2,713	2,712
Low Carbon Life	2,928	2,746	2,722	2,719

6. The Base cost (cost of procuring the actual scenario) is subtracted from the above costs to give the absolute regret cost. The table below shows this:

Table 30: Regret cost by scenario combination

Scenario	Base Costs £m	Procure Gone Green £m	Procure Slow Progression £m	Procure No Progression £m	Procure Low Carbon Life £m
Gone Green	2,592	0	26	58	61
Slow Progression	2,671	67	0	7	7
No Progression	2,713	199	24	0	1
Low Carbon Life	2,719	209	27	3	0

7. The maximum regret cost is taken from each scenario. The table below shows this

Table 31: Maximum regret cost by scenario

Scenario	Procure Gone Green £m	Procure Slow Progression £m	Procure No Progression £m	Procure Low Carbon Life £m
Maximum Regret	209	27	58	61

8. The minimum of the above maximum regret costs is £27m, associated to Slow Progression and leads to the capacity to procure of 52,975 MW.

Note that the actual Least Worst Regret process used a wider range of scenarios and sensitivities to derive the recommend capacity to procure. See Chapter 6 for further details on the Least Worst Regret analysis carried out for the 2015 ECR.

8.4.3 Sensitivity Analysis

Our recommendation in the 2015 ECR is based on Least Worst Regret (LWR) analysis applied to all of National Grid's scenarios and sensitivities, all given equal weighting in the calculation.

In accordance with the agreed approach and given that the recommended capacity to procure corresponds to the value on the CM demand curve for the net CONE capacity cost, the analysis used DECC's published central estimate of VoLL (£17,000/MWh) and net CONE (£49,000/MW/yr) values.

However for information only, analysis has been carried out to check how sensitive the results were to these assumptions and to the inclusion or weighting of particular sensitivities. In particular, the following sensitivity analysis was carried out on the calculation:

- Applying weightings for cold winter (0.4) and warm winter (0.13) sensitivities based on relative winter (December to February) severity derived from 30 years (1 in 5 cold for 2010/11 and 1 in 15 warm for 2006/07) compared to mean (1 in 2)
- Removing the low and high conventional plant availability sensitivities
- Using lower and higher unit capacity costs of £31,000/MW/yr and £62,000/MW/yr respectively derived from a range of modelled bid prices for new CCGTs.
- Using DECC's published low estimate of VoLL (£10,000/MWh) based on domestic customers only[45] as the unserved energy unit cost

The results are summarised in the table below compared to the recommended capacity to procure.

Table 32: Least Worst Regret Sensitivity Analysis Results

Description	LWR Capacity (GW)	LWR Marginal Case
Recommended capacity	47.9	CP High Avail.
Cold / Warm winters weighted	47.9	CP High Avail.
Low / high avail. excluded	48.0	SP
Lower cost (£31,000/MW/yr)	48.5	SP High Demand
Higher cost (£62,000/MW/yr)	47.7	SP High Avail.
VOLL £10/kWh	47.0	GG

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

Some observations from this analysis are as follows:

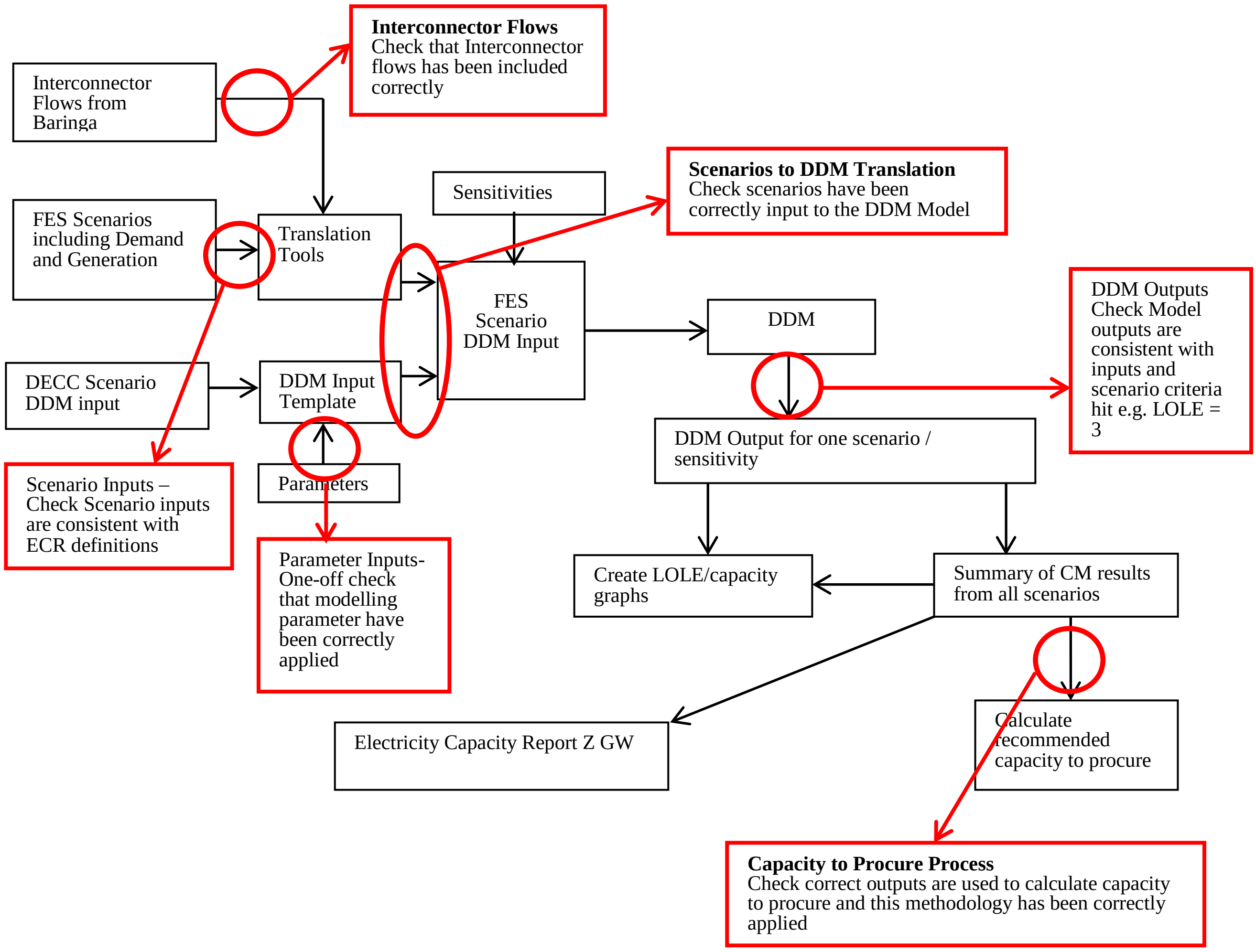
- Changing the assumptions in general did not have a significant impact on the LWR capacity.
- The weighting of cold / warm winter sensitivities had no impact on the LWR capacity.
- Excluding the low / high availability sensitivities increased the LWR capacity by 0.1 GW.
- Using a lower capacity cost increased the LWR capacity by 0.6 GW. This is comparable to the 0.7 GW procurement above the target in the 2018/19 T-4 auction resulting from a clearing price below net CONE.
- Using a higher capacity cost increased reduced the LWR capacity marginally by 0.2 GW.
- Using a lower VoLL estimate reduced the LWR capacity by 0.9 GW.

8.5 Quality Assurance

When under taking any analysis National Grid looks to ensure that a robust Quality Assurance (QA) process has been implemented. National Grid have worked closely with DECC's Modelling Integrity team to ensure that the QA process closely aligned to DECC's in-house QA process[46]. We have implemented the QA in a logical fashion which aligns to the project progression, so the elements of the project have a QA undertaken when that project "stage gate" (such as inputting data in to a model) is met. This approach allows any issues to be quickly identified and rectified.

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

Figure 29: QA checks process diagram



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.

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

These steps are:

- Interconnector flows – Check the interconnector flow distributions and capacities
- Scenario inputs – Check the model input assumptions
- Parameter Inputs – Check the model setup assumptions
- Scenarios to DDM Translation – Check the input from the FES process into the DDM model
- DDM model – The model which will be used to calculate the LOLE and capacity to procure
- DDM Outputs - Check model outputs are consistent with inputs and scenario criteria
- Capacity to Procure Process – Check the inputs and outputs used to determine a range and recommended capacity to procure

Below is detailed QA process for each of these steps.

Scenario Inputs

The FES process is driven by extensive stakeholder engagement[47], workshops and bilateral 1-2-1 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 System Operator (SO) Executive Committee. The assumption and outputs will be published in the annual FES document on July 15th 2015.

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

The parameters are set to ensure that the model runs as required for the ECR process. These parameters are checked and documented by two analysts to ensure that they are correct and then a final template is created (with a backup) which all runs are then based on. This check also include that CM results are correctly included in the input template.

Scenarios to DDM Translation

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

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

DDM model

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
- Internal reviews by DECC

Details of these can be found in the 2013 EMR Delivery Plan document. These imply that a further QA of the DDM is not required as part of the ECR QA process. However, to ensure that the DDM is the correct model to use, and that it is being used correctly, the PTE have been specifically asked to QA the use of DDM for ECR. During last year, the owners of DDM, consultants Lane Clarke Peacock (LCP)[48], were asked to ensure that National Grid was both using the model, and interpreting the outputs, correctly. This involved a bilateral meeting between National Grid and LCP to discuss in detail the modelling being undertaken. This highlighted some minor issues which have been resolved. LCP produced a report of their QA process. The report concludes that National Grid is using the model correctly and correctly interpreting the output results. Following modelling verification exercise it has been agreed with DECC that this will not be required for this year.

DDM Outputs

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

QA Check List Process

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

Capacity to Procure Process

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

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 Market Operation.

8.6 Historical Demand Forecasting Performance

The low and high demand sensitivities cover the demand uncertainty due to the underlying (i.e. weather-corrected) ACS peak “Unrestricted GB National Demand” forecast performance (see 3.2.1). These sensitivities are based on transmission demand as this is metered and can be validated. Ideally we would use forecast total GB demand, but distributed generation isn’t metered and therefore can’t be validated.

The sensitivity is based on the average winter ahead (T-0) forecast errors over the last 7 years. The individual forecast errors are shown in Table 33[49]. Table 34 shows the average forecast error for each year, defined as the average of all forecasts made in that particular year. This ensures that all years have equal weighting. The average forecast error is calculated as the average of the forecast errors for each of the last 7 years and is equal to 1.2% as shown in Table 34. The standard deviation of the forecast errors is 2.1%. The fact that the forecast error is positive implies a tendency to over-forecast ACS peak demand. The high and low demand sensitivities are constructed by subtracting the average forecast error of 1.2% and then adding/subtracting 2.1% to the ACS peak demand. This results in an asymmetric range from +0.9% (high demand) to -3.3% (low demand).

Table 33: T-0 Forecasts (i.e. within year winter ahead)

Forecast Year	Forecast period	Forecast Demand (GW)	Actual Demand (GW)	Error (GW)	% Error
2008/09	Apr 08 Forecast	60.3	58.4	1.9	3.3%
2009/10	Apr 09 Forecast	56.5	57.5	-1.0	-1.7%
2009/10	2009 Gone Green	56.6	57.5	-0.9	-1.6%
2010/11	2010 Slow Progression	57.5	58.1	-0.6	-1.0%
2011/12	2011 Slow Progression	58.1	55.8	2.3	4.1%
2011/12	2011 Gone Green	58.1	55.8	2.3	4.1%
2012/13	2012 Slow Progression	55.9	56.2	-0.3	-0.5%
2012/13	2012 Gone Green	56.7	56.2	0.5	0.9%
2012/13	2012 Accelerated Growth	56.6	56.2	0.4	0.7%
2013/14	2013 Slow Progression	56.3	55.3	1.0	1.8%
2013/14	2013 Gone Green	56.5	55.3	1.2	2.2%
2014/15	2014 Gone Green	55.0	54.3	0.7	1.3%
2014/15	2014 Slow Progression	55.0	54.3	0.7	1.3%
2014/15	2014 No Progression	55.0	54.3	0.7	1.3%
2014/15	2014 Low Carbon Life	55.0	54.3	0.7	1.3%

[49] See also chart on page 32 of https://www.ofgem.gov.uk/ofgem-publications/94543/initialproposalconsultationemrfundingandincentives-pdf

Table 34: Average Forecast Error %

Forecast Year	Average Forecast Error (GW)	Average Forecast Error %
2008/09	1.90	3.3%
2009/10	-0.95	-1.7%
2010/11	-0.60	-1.0%
2011/12	2.30	4.1%
2012/13	0.20	0.4%
2013/14	1.10	2.0%
2014/15	0.70	1.3%
Overall Average	0.66	1.2%
Standard Deviation	1.21	2.1%

Index of Figures

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