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De-rating Factor Methodology for Renewables Participation in the Capacity Market

Consultation Response Summary

25 February 2019

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Executive Summary

The EMR Delivery Body, as part of National Grid Electricity System Operator (ESO), launched an industry consultation in January 2019 on the proposed method for calculating de-rating factors for wind and solar, should they be allowed to participate in the Capacity Market (CM). As per the Rules, this consultation was concerned with the technical method of calculating de-rating factors and not the policy around CM participation or any other wider policy issues. While respondents raised some interesting policy-related comments and questions these are outside of the scope of this technical consultation and as such will be passed to BEIS and Ofgem for consideration as part of their wider consultation processes.

This document sets out the modelling method and results and provides a summary of the feedback we received to each of the six consultation questions. Some participants asked additional technical questions and these are addressed in Chapter 3. We also offer some brief conclusions and provide an overview of next steps in response to the consultation and as part of ongoing planned work activities.

We remain confident that the method proposed in this consultation is robust and fit for purpose. Throughout the process of developing the method we consulted academic advisors at the University of Edinburgh and BEIS' independent Panel of Technical Experts. The method was also benchmarked against other internationally recognised approaches. Nevertheless, we recognise that this does not mean the method is now cast in stone and we will continue to review all our modelling techniques, including this one, to ensure that they remain up to date and take account of the latest data and market developments.

To this point, we will look to update the wind power curves annually as more data becomes available for the larger sized turbines. This may subsequently lead to the consideration of using more than one power curve for onshore wind, noting that a sound evidence base would be prerequisite to this happening.

Two additional areas that will require development work over the next year or two relate to hybrid technologies, where there is a network connection constraint and distribution connected technologies, as they currently use equivalent transmission technology de-rating factors which will becomes less appropriate as markets become more flexible.

While broad support for the use of incremental Equivalent Firm Capacity (EFCs) for new projects was evident in the responses received, several respondents questioned whether it is appropriate to use incremental EFCs for existing wind farms e.g. once support under the Renewables Obligation (RO) expires. Admittedly, this is not a clear-cut issue and as such we have provided additional quantitative modelling results to further demonstrate the reasons for using an incremental EFC approach for wind and solar PV de-rating factors in the foreseeable future. We identify that the difference between incremental EFC and average EFC for the CM eligible wind remains close and stable until the CM eligible wind capacity reaches >8GW sometime approaching 2030.

Finally, the illustrative results from the method are shown below:

Indicative De-rating factors for wind and solar

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	De-Rating Factors (%)		
Target Year	**Onshore Wind**	**Offshore Wind**	**Solar PV**
T-1 2020/21	8.98%	14.65%	1.17%
T-3 2022/23	8.40%	12.89%	1.76%
T-4 2023/24	8.20%	12.11%	1.56%

Note, that we plan to update these de-rating factors in March to reflect the latest MERRA data, including 2017/18 and the "Beast from the East", and the new draft Future Energy Scenario Base Case capacity projections for wind, solar and storage for each target year but we are not expecting any significant changes to them.

1. Modelling methods and results summary

1.1 Key metrics

The main metrics used in the renewables de-rating factor methodology are described below.

Loss of Load Expectation (LOLE)

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

The Government's Reliability Standard for GB is 3 hours LOLE / year.

Expected Energy Unserved (EEU)

This is the expected amount of electricity demand (measured in MWh) that is not met by available generation during a year before any mitigating / emergency actions are taken but after all system warnings and System Operator (SO) balancing contracts have been exhausted.

Equivalent Firm Capacity (EFC)

Equivalent Firm Capacity is a useful metric to assess the security of supply contribution of non-conventional adequacy resources

- An EFC is defined as "for a penetration of that resource, what is the amount of perfectly reliable firm (100% available) capacity it can displace while maintaining the exact same risk level (as defined by a suitable statistical risk metric)"
- EFC can be defined with respect to either the LOLE or the EEU risk metric
- EFCs can be expressed as a percentage of capacity – these are referred to as EFC%s

Note also that there are some important distinctions between:

- The "incremental" EFC of a small amount (e.g. 20 MW) of the resource added to the margin of the base case
- The "average" EFC of the entire fleet of that resource type in the base case
- The "combined" or total EFC of a set of fleets of different technology types which may exhibit some interactions

1.2 Modelling approach

For the renewables' de-rating factor modelling we used LCP's Unserved Energy Model (UEM) which is a time sequential Monte Carlo simulation model of GB capacity adequacy.[1] This tool is related to LCP's Dynamic Dispatch Module (DDM) software used in our annual Electricity Capacity Report (ECR) and preserves general consistency of GB system data and plant representation.

For this consultation, the UEM model used 12 winters (November to March) of time-coincident wind, solar and demand data as well as a two-state (fully-available/fully-unavailable) representation of conventional plant technical availability and its mean-time-to repair (MTTR) and a simulation of storage operation based on four different algorithms.[2]

[1] Lane, Clark and Peacock LLP – see http://www.lcp.uk.com/
Given that the software rights are owned by LCP, we cannot provide consultees with access to the UEM, but consultees may wish to approach LCP if they are interested in carrying out their own analysis.

[2] As described in previous storage de-rating factor report - see https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

We commissioned LCP to update the UEM so that it could calculate the:

- "Incremental" EFCs of wind (offshore/onshore), and solar PV [in addition to the duration-limited storage categories already calculated by the UEM]
- "Average" EFCs of the [entire wind], or [entire solar PV], or [entire storage] fleets considered individually
- "Combined" EFC of all [wind plus storage plus solar PV] resources considered together

A broad outline of the method used by the UEM to calculate EFCs can be found in the consultation slides.

Wind and solar power curves

To generate time-coincident wind data we reviewed and updated the wind power curves for onshore and offshore wind. This review took cleansed data related to historical metered wind power output, as well as historically measured average half-hourly wind speeds (from our weather service provider) for winter 2017/18 for a sample of existing wind farms. We then used an optimisation tool to derive a best-fit curve between the two datasets to create empirical wind power curves for onshore and offshore wind (see Section 3.2 below for further details).

Next we used the GPS locations and hub heights of a credible future GB wind farm fleet (onshore and offshore) in conjunction with the NASA MERRA atmospheric reanalysis dataset and the updated wind power curves to derive a dataset of time coincident onshore and offshore wind fleet load factors covering the 12 winters (2005/06 to 2016/17).

For solar PV, the power curve utilised a recent NIA Project carried out between National Grid ESO and University of Reading that derived a single power curve for all GB solar PV resources by developing an empirical relationship between past solar PV power measurements (from the Sheffield Solar monitoring project) and the NASA MERRA solar PV irradiance data set.[3] The University of Reading used this power curve to derive solar PV load factors covering the 12 winters (2005/06 to 2016/17) for the current solar PV fleet, taken as being representative of the geographical distribution of the future solar PV fleet.

MERRA data validation

As part of their work on the Network Innovation Allowance (NIA) project "NIA_NGET0183", the University of Reading validated the performance of nationally aggregated wind and solar models derived using MERRA wind and solar data. They concluded that MERRA accurately captures the large scale meteorological features and therefore provides a good representation of the national level wind and solar generation which supports the use of the MERRA data in deriving the national de-rating factors derived for this consultation

The University of Reading also advised that the MERRA data should not be used for individual sites or even relatively small geographical regions. This is one of the reasons why we didn't use MERRA wind speed data to derive wind power curves for the selected sample of wind farms.

Further details on the work carried out by the University of Reading can be found in the consultation slides and by visiting the websites referenced in Annex 1 of the slides.

Wind, storage and solar PV installed capacities

We set up Base Cases with a credible supply portfolio, for each of the CM target years: 2020/21 (T-1), 2022/23 (T-3) and 2023/24 (T-4). The solar PV, onshore/offshore wind and storage penetration levels in the Base Cases broadly correspond to the 2018 ECR Base Case assumptions. The Base Case was adjusted to meet the Reliability Standard of 3 hours LOLE/yr.

[3] Future updates of the solar PV power curve could consider using other data sources (e.g. from solar PC developers) if it is made available to National Grid ESO.

The installed capacities of onshore wind, offshore wind and storage for each of the target years can found in slide 18 of the consultation slides. These broadly align to the 2018 ECR Base Case assumptions.

1.3 Sensitivities modelled

We assessed a large number of sensitivities around the T-3 Base Case looking at:

- Individually increasing penetrations of wind or solar, assuming zero storage, for both EEU and LOLE.
- Collectively increasing penetrations of wind and solar together, assuming zero storage, for EEU.
- Individually increasing penetrations of wind or solar, with various penetrations of storage, for EEU.
- Collectively increasing penetrations of wind, solar and storage all together for EEU and LOLE.
- A credible future GB scenario level of wind, storage and solar at different base reliability levels, for EEU.
- A credible future GB scenario level of wind, storage and solar with different MW sizes of the incremental wind and solar EFC units applied to the margin, for EEU.
- Impact of the new updated wind turbine power curves on wind EFC calculations.

Further details including the wind, solar and storage capacities assumed for the sensitivities can be found in the consultation slides.

1.4 Results and indicative de-rating factors

Key observations from modelling results

Listed below are the key points observed in the modelling results for wind and solar:

- Wind incremental EFC%s are lower than the (~15-20%) average EFC that is typically seen in Winter Outlooks. This is because the output from a new wind farm is highly correlated to the output of the existing fleet and the more already on the system, the less additional contribution it makes to security of supply. With 15-year contracts available in the CM for new capacity, we need to properly reflect the incremental value of the next new project to the system.
- Offshore wind turbines are bigger, taller and have better wind regime and hence they would merit separate treatment compared to onshore wind farms.
- Solar PV has a small but non-zero incremental value to the system. This is primarily due to the interaction with duration limited storage, where solar availability on peak demand days allows battery storage to be discharged later in the evening than would otherwise be the case. The effect is relatively small, for now.
- The combined EFC of [wind, storage, solar] together is slightly distinct from the sum of individual average EFCs –this is due to statistical interactions of all three resources. The effect is relatively small, for now, but has the potential to become significant in the future.
- To date we have used LOLE as the risk metric for wind power and EEU for storage. However, we noticed that when calculating incremental EFCs for wind using LOLE that the value differs based on which coordination algorithm is assumed for storage operation during stress events. With EEU as the risk metric the incremental wind EFC value is far more stable. This suggests EEU is the better risk metric to use for all incremental de-rating factors and it ensures consistency for all non-conventional capacity.
- All EFC de-rating factor results in the CM are provided for a Base Case at 3 hours LOLE we propose to be consistent with this for wind and solar participation. As per previous observations in Winter Outlook analyses, then the tighter the margin (higher LOLE), then the higher the wind and solar PV EFCs will be, as they can make a better contribution to more and deeper stress events.
- This size of the marginal unit does not seem have a material impact on the incremental EFC%s derived with EEU as the risk metric. Hence, we propose to continue with the use

- of 20MW incremental sized unit to be consistent with the approach used for the duration-limited storage EFC calculation to date.
- The 2018 wind turbine power curve update makes the onshore wind EFC a little better (~ 2 %) and the offshore wind EFC a little worse (~ 3%) compared to the previous curves used. However, the overall wind fleet 'average' EFC remains almost the same as the changing onshore / offshore effects largely balance each other out, so the effects on the combined EFC are relatively small. We propose to use the updated 2018 wind power curve for the analyses henceforth.
- Wind incremental EFC%s reduce slightly as wind capacity increases for both onshore and offshore wind.
- Solar incremental EFC%s increase slightly as solar PV capacity increases. However, the solar PV EFCs may increase more if there is big expansion in storage on the system.
- The "non-additivity" difference between the 'Combined' EFC and the sum of individual 'Average' EFCs becomes more appreciable, indicating that the interactions become more complex in the future system

Indicative de-Rating factors

Table 1 shows the indicative de-rating factors for solar PV, onshore and offshore wind based on incremental EFC%s and the EEU risk metric.

	De-Rating Factors (%)		
Target Year	**Onshore Wind**	**Offshore Wind**	**Solar PV**
T-1 2020/21	8.98%	14.65%	1.17%
T-3 2022/23	8.40%	12.89%	1.76%
T-4 2023/24	8.20%	12.11%	1.56%

These de-rating factors will be updated in March using an updated view of storage, wind and solar PV penetrations in the target years and an extra year of time-coincident demand, wind and solar PV data covering winter 2017/18.

1.5 Stability of results

As previously discussed, with EEU as risk metric the incremental EFC%s are stable regardless of the assumption made on storage operation during stress events. In addition, as capacity increases onshore and offshore wind incremental EFC%s reduce only slowly. Solar PV EFC%s remain stable as capacity increases, rising very slightly. This stability supports the adoption of EEU as the risk metric and incremental EFC% as the basis of the de-rating factors.

The incremental EFC%s are also very stable with respect to the size of the incremental unit. Although we have used a 20 MW incremental unit to be consistent with storage, the incremental EFC%s would be very similar if we used an incremental unit of several hundreds of MW in size as per some of the new wind projects. More details on how incremental EFC% is impacted by different factors can be found in the consultation slides.

1.6 Validation of outcome and choice of metric

We conducted extensive stakeholder engagement on our proposal to use EEU as a risk metric and incremental EFC% as the basis for wind and solar PV de-rating factors. As a result of stakeholder engagement activities, we are confident that the methodology being proposed is representative of the state of the art in this area. Stakeholder engagement has validated our approach as detailed below.

International engagement

We shared our experience with other system operators, academics, and industry representatives in Europe via a collaborative research paper presented at the 2018 Wind Integration Workshop in Stockholm. We also engaged with US based industry representatives via the IEEE Loss of Load Expectation (LOLE) Working Group at the Summer 2018 General Meeting.

We note that Eirgrid, the System Operator in Ireland, also uses an incremental / marginal EFC% approach for wind de-rating in their Capacity Market.[4] Their most recent CM auction parameters list a ~ 10% de-rating factor for wind; this is not yet separated into onshore/offshore split as there is no material offshore wind market in Ireland at present.[5] The Irish CM structure is very similar to the GB one and therefore the similar incremental wind de-rating factor should give further comfort that the proposed direction is a robust one. The reasons for the solar de-rating factor being slightly higher are not fully clear, though one hypothesis is that (a) Ireland is longitudinally a little more to the west than Great Britain though on the same time-zone, and therefore the sun shines a little later in the afternoon on winter peak days and (b) the Irish system reliability standard is 8 hours LOLE and as shown on slide 24 in our consultation pack, the higher the LOLE reliability standard on the system then the better the renewables EFC%s will tend to appear.

Independent academic advice

We sought expert advice and data input on weather modelling from Dr. Daniel Drew, University of Reading, who is currently on sabbatical at National Grid ESO. We received additional advice from independent academic consultants at the University of Edinburgh (Dr Chris Dent, Dr Stan Zachary and Dr Amy Wilson) on matters related to risk modelling with renewables. They advised us to use incremental EFCs as the basis of de-rating factors in the capacity market. Our academic consultants stated that:

> *"We assume that the objective of a capacity auction is to obtain the required level of security-of-supply (as measured by whichever risk metric is chosen for this purpose) at minimal cost. For this to happen it is necessary that the contributions of the various facilities participating in the auction as measured by their EFCs are correctly valued relative to each other at the point where the market clears. This is, at least in principle, the point at which it is considered that sufficient capacity has*

[4] See page 18 of https://www.semcommittee.com/sites/semc/files/media-files/SEM-18-030a%20Appendix%20A%20TSO%20Capacity%20Requirement%20and%20De-rating%20Factors%20Methodology%20June%202018_0.pdf

[5] See page 8 of https://www.sem-o.com/documents/general-publications/Initial-Auction-Information-Pack_IAIP1920T1.pdf

been obtained to meet the required standard and is at present that defined by the current standard of 3 h/y LOLE.

To see this, note that typically a capacity auction accepts bids in ascending order of their cost to EFC ratios until sufficient capacity is obtained. At this point it should not be possible to identify an unsuccessful participant providing capacity at lower unit cost than a successful participant otherwise the former should be swapped for the latter both so as to reduce the overall cost of providing sufficient capacity, and also of course as a matter of market fairness. The measure of capacity contribution is thus the incremental (or marginal) EFC evaluated at the point where such transactions might be considered, i.e. at the point where the market is expected to clear. Thus, the appropriate measure of capacity contribution of any facility participating in the auction is that level of firm capacity which results in the same reduction in the risk metric at this point." [Source: Dent, Wilson and Zachary]

Note that for conventional capacity market resources, the de-rated capacity used in the auction already approximates to its incremental EFC at 3 hours LOLE / year.[6] Using incremental EFC for non-conventional resources would ensure consistency and fairness.

Panel of technical experts

We consulted with BEIS and Ofgem, as well as the BEIS Panel of Technical Experts who endorsed the approach of using incremental EFC%s with EEU as risk metric.[7]

"We concur with National Grid's recommendation to use incremental EFCs for the determination of incremental capacity value for new renewables bidding in to the Capacity Mechanism, *if and when they are brought in to this system**.** As detailed in NG's presentation, for a given system structure (in terms of other components) this will decline steadily as the capacity increases, a finding consistent with academic literature, logic, and international experience. We note that it will also depend on system structure, including the amount and nature of storage, and thus incremental EFCs would need to be kept under review.*

If wind were to be included in the CM, and particularly if it is eligible to receive 15-year contracts, such contracts could contribute to investment incentives. Using average EFCs for capacity remuneration would therefore result in incentives for wind investment greater than justified on grounds of their contribution to system security.

However, we also emphasise that ***when determining the total amount of generation capacity that is needed to meet the GB security standards, average EFC*** *for renewables should be used, not incremental. Put simply,* ***the total*** *amount of conventional generation capacity that can be displaced by wind generation, increases with wind generation (i.e. we will need less conventional generation to meet the security standard), but the* ***marginal contribution*** *of each additional unit declines."* [Source: Panel of Technical Experts on Electricity Market Reform]

[6] Shown via use of the "Garver approximation": If a conventional unit of capacity C has availability probability (de-rating factor) of p and is assumed to be an independent binary unit i.e. its available capacity is either C (with probability p) or 0 (with probability 1-p), then its incremental EFC is approximately $(-1 / \lambda) * \log_e((1 - p) +(p * e^{-(C * \lambda)}))$ which is approximately $C * p$ (its de-rated capacity) for typical values of the exponential decay parameter λ at 3 hours LOLE / year (see Annex of 2017 ECR for further details on this decay parameter)

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

2. Summary of responses

The EMR Delivery Body received a total of fourteen responses to its industry consultation on the de-rating factor methodology for renewables participation in the Capacity Market (CM). The summaries below set out respondent's views on the proposition put forward in our January consultation document.

Where we indicate the proportion of respondents that expressed a view on a proposition, this is from the total that commented on the specific question rather than the total number of responses we received to our consultation.

Some parties raised additional, specific questions and these have been addressed in section three of this response document.

Please note that we do not intend to publish the consultation responses received.

Question 1: Should we have separate Capacity Market technology sub-categories for onshore and offshore wind turbines?

Nine respondents addressed this question and all agreed with the assessment that separate technology sub-categories for onshore and offshore wind turbines was sensible and workable. This was reasoned on the basis that higher offshore wind speeds merit a better CM de-rating factor and that load factors and contribution to security of supply differ significantly for onshore and offshore wind.

Most respondents suggested that further sub-division on a locational basis should be considered in the future. It was generally held that the difference in typical onshore load factors between Scotland and parts of England should be reflected appropriately in the de-rating factors. A similar case was made for the future introduction of a sub-division based on hub height/rotor diameter, given the potential for performance improvements in turbine technology. It was considered that this may help to ensure that wind is properly valued and rewarded for its contribution to security of supply. In addition, for solar, one respondent pointed out the regional variability in irradiance and PV capacity factors.

National Grid ESO response

We welcome the strong support for separate technology sub-categories for onshore and offshore wind turbines to help ensure that the respective de-rating factors correctly reflect differences in the load factors achieved. We recognise that the suggested regional sub-division would seem logical, but note that this would require further analysis to ascertain whether higher load factors observed over a year then translate into higher de-rating factors at periods close to or at times of system stress. We also observe that the rules would not currently permit regional sub-divisions as the CM is non-locational. The feasibility of introducing regional onshore de-rating factors is discussed further in chapter three of this report.

Question 2: How to calculate the contribution of wind and solar PV resources to security of supply in a technology-neutral manner using Equivalent Firm Capacity (EFC)?

8 responses were received for this question. Of these, four agreed that EFC was an appropriate method to calculate the contribution of non-conventional, wind and solar PV resources to security of supply. Several respondents emphasised a need for the power curves to be recalculated and updated on a regular basis to incorporate any advancements in turbine technology and ensure that de-rating factors remain accurate, noting the relevance of the power curve to future investments.

Of the three parties who opposed the use of EFC, one questioned the longer-term suitability of the methodology as we move towards a smarter and more flexible system and argued that it was also not technology agnostic. Another considered the methodology to be flawed since the sites modelled are not eligible for the CM and are not, therefore, reflective of the turbines that would potentially bid in the 2020/21 auctions. It was also suggested that a broader focus should be adopted when calculating the contribution of wind to security of supply so that factors beyond just stress events are taken in to account.

National Grid ESO response

We agree that the wind and solar PV power curves should be subject to periodic review in response to future substantive improvements in turbine technology to ensure that the methodology and resulting de-rating factors continue to be accurate.

We do not agree that the methodology is flawed because of the sites modelled, nor do we agree that the definition and use of EFC is unworkable in a future energy system that is smarter and more flexible as our sequential model takes account of these interactions and will be updated as the system evolves and new data becomes available. The points raised that are policy-related will be forwarded to BEIS for consideration.

Question 3: Should we use 'Average or 'Incremental' EFCs as the basis for the de-rating factors?

Nine responses were received in answer to this question. Most respondents agreed with our assessment that incremental EFCs should be used as the basis for the de-rating factors. Of the responses in support of incremental EFCs, there was a common trend in favour of applying different EFCs to existing and new renewable generation. Respondents considered that an incremental EFC was appropriate for new or planned renewable generation, given the incremental value of this capacity to the system, while an average EFC should be applied to existing generation to avoid undervaluing their contribution to security of supply.

One respondent noted that further clarification as to the distinction between incremental and average EFC calculation as it related to solar PV would be useful to make an assessment. A further respondent was opposed to the adoption of incremental EFCs and argued that the participation of renewables would become minimal as de-rating factors decreased over time.

One respondent was 'strongly' in favour of average EFCs as the basis for the de-rating factor applied to renewables, asserting that the consultation paper had failed to provide sufficient analytical justification to support the use of incremental EFCs.

National Grid ESO response

We welcome the broad support for the use of incremental EFCs to calculate de-rating factors.

In light of the comments received about the appropriateness of using incremental EFC for de-rating wind, once support under the RO expires, we have examined whether this issue is likely to become material. The additional quantitative modelling results, detailed in section three, support our original proposed direction to use an incremental EFC approach for wind and solar PV de-rating factors for the foreseeable future. We note that this issue will be monitored and reviewed if there is material growth in the participation of renewables in the CM.

Question 4: What are the interactions, if any, with duration limited storage on the system?

There were 8 responses to this question. Respondents were split 50/50 on whether the interactions with duration limited storage on the system are minor or significant in nature. Among those respondents who supported our assessment, it was generally held that solar and storage had a clear positive additivity effect and that the solar PV de-rating factor may grow in time, dependent upon the expansion of battery storage on the system.

Those respondents who determined the interactions to be 'complex' and 'substantial' highlighted that de-rating for solar and storage should in fact be treated separately, with individual technologies assessed on a stand-alone basis.

One respondent had reservations about the 'formal link' made between the operation and interactions of different technologies because it is not yet clear that storage units will be used by renewable generators to shift output over time.

National Grid ESO response

Our view remains that combined EFC interactions are, for now, small in their effect but we acknowledge the future potential for combined EFC interactions to grow over time as the GB system continues to change.

Question 5: Which EFC statistical risk metric makes most sense for wind and solar – unserved (EEU) or Loss of Load Hours (LOLE)?

Across the six responses to this question, there was broad agreement with our conclusion that EEU delivers a more stable de-rating factor when compared with LOLE. One respondent highlighted that using the same metric as currently applied to limited duration storage is also sensible as it allows for an easier calculation and integration of hybrid sites in the future.

One respondent said that there was insufficient data to understand the implications between whether a risk metric or a capacity deficiency metric is the best methodology for analysing wind and solar in the first instance, and the insufficiency of the evidence precluded a definitive conclusion on the use of either EEU or LOLE.

National Grid ESO response

We welcome the strong support we received from respondents around the proposal to calculate the EFC with an EEU risk metric, and the broad agreement with our view that EEU is more robust in its ability to capture any effects related to storage coordination assumptions during stress events.

We note the point raised about the suitability of a risk metric versus a capacity deficiency metric, but observe that the broader category of metric used in the methodology was not itself in question.

Question 6: How do all of these trends change as the penetrations of the resources increase in future?

There were nine responses to question 6. Most respondents emphasised a need to ensure that modelling assumptions are refreshed on an annual basis so that they remain accurate in response to any significant future changes in technology and as more data on the interactions between wind, solar and storage becomes available.

One respondent did not believe that the methodology took sufficient account of longer term changes to the network, with the role of flexibility and dependency on storage for security of supply unaccounted for.

Another respondent advised that reaching a clear determination was difficult since future trends are in part contingent on how some technologies seek to obtain revenue via other services such as Fast Reserve.

National Grid ESO response

We agree with the view that we should periodically review modelling assumptions and the power curves for both onshore and offshore wind as more data becomes available. We will look to undertake this review on an annual basis as part of our ongoing future modelling developments work.

We note the concerns raised by two parties that security of supply and the ability of certain technologies to deliver during a stress event is dependent on flexibility and speed of response although care needs to be taken not to confuse operability with adequacy and how they are funded.

3. Response to additional technical questions

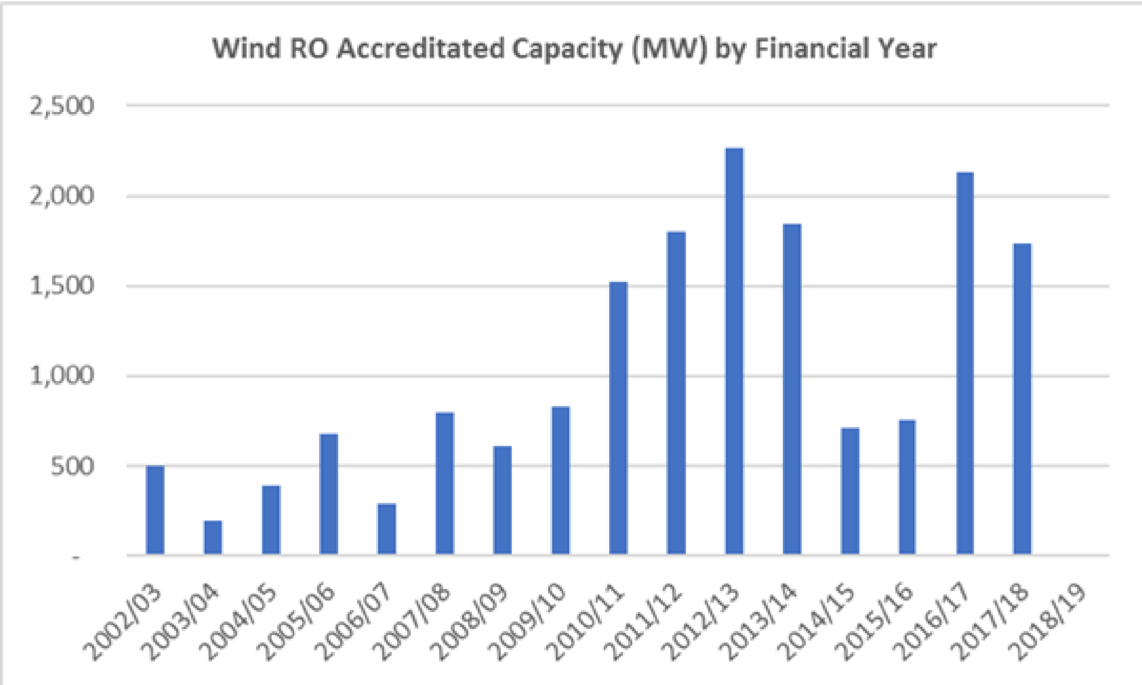
3.1 Incremental v Average EFCs impacted by existing wind farms leaving the RO?

While generally supportive of using incremental EFC%s for new projects, several consultation respondents questioned whether it is appropriate to use incremental EFC%s for existing wind farms once their support under the Renewables Obligation (RO) expires. A sample of comments on this issue are detailed below:

- …'we therefore suggest that the de-rating methodology uses the average EFC to de-rate existing renewable generation assets (as is the case at present); but that any new renewable projects are de-rated on the incremental EFC basis, reflecting the incremental value of the new capacity to the system'.
- ...'we would therefore recommend that the methodology uses the average metric for existing projects, and incremental for new projects'.
- …'an incremental de-rating factor for existing plant (e.g. those leaving a subsidy mechanism in the future) undervalues the overall economic contribution of wind to supporting security of supply and might therefore result in economically-inefficient decisions'.
- "…it is worth considering whether an average EFC approach is more appropriate for existing operational plant looking to bid into the CM for a 1-year agreement'

To examine this issue further we considered whether, and if so, when this issue is likely to become material. The below chart presents estimated capacities of GB RO supported wind farms that were awarded agreements from 2002 onwards.[8] Given that the RO agreements were for a duration of 20 years, it can be expected that these annual blocks of capacities may become eligible for the CM as they start to roll out of their RO contracts from CM delivery year 2022/23 onwards. Note that projects supported by Contracts for Difference (CfDs) generally have 15-year contracts which will begin to expire from 2030 onwards.

Figure 1: RO Accredited Wind Capacity by Financial Year



[8] This data was downloaded from Ofgem's website at https://renewablesandchp.ofgem.gov.uk/Public/ReportViewer.aspx?ReportPath=/Renewables/Accreditation/AccreditedStationsExternalPublic&ReportVisibility=1&ReportCategory=1 by selecting all projects for England, Wales, Scotland.

Ordinarily stakeholders are used to hearing about a ~ 15-20% wind EFC figure in the annual Winter Outlook process. However, it should be noted that the figure reported in the Winter Outlook refers to the security of supply contribution of ALL wind on the system, which we quantify via an average EFC assessment, regardless of what support mechanism may be funding it. By contrast, the EMR de-rating for renewables consultation was tasked with valuing the additional or incremental contribution to security of supply from wind that may be funded by the CM, i.e. assessing that extra capacity value over and above the contribution which is already provided by non-CM-eligible wind.

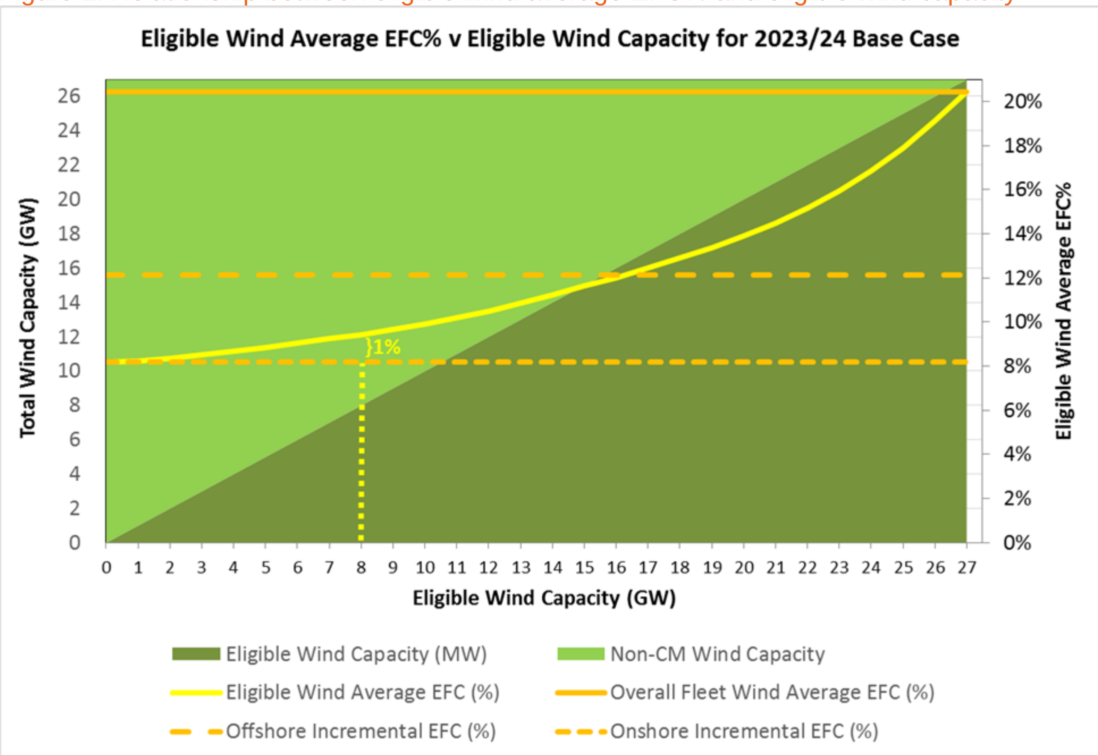
It is important to note that regardless of whether future CM eligible wind sites are newly built or in existence via the RO / CfD schemes, they are ALL new to the CM from the point of view of providing a security of supply contribution over and above the contribution from non-CM eligible wind that is already accounted for outside the CM auction. The non-CM eligible wind contribution to security of supply is necessarily subtracted from the required capacity to secure in each Electricity Capacity Report (ECR) prior to the auction being carried out, as it is already paid for by the consumer via another route.[9] We have calculated the total contribution to security of supply from the total amount of CM eligible successful wind in future years and have shown its value to be almost the same as the incremental EFC% proposed for the de-rating factor analysis.

Case studies to quantify the materiality of the issue

To assess the materiality of industry concerns about fairness, we calculated the difference in the contribution to security of supply that any future CM eligible wind projects provide, using the 2023/24 Base Case with ~27 GW of wind:

- Individually via the incremental EFC metric which is proposed for the de-rating factors
- Collectively via the "average EFC of the successful-CM-auction wind capacity". Note that this is a distinct quantity/term to the "average EFC of the entire (CM-eligible plus non-CM eligible) wind fleet overall" which is quoted in our Winter Outlook process, as that average EFC accounts for the contribution of all wind on the system.[10]

Figure 2: Relationship between eligible wind average EFC% and eligible wind capacity



[9] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/189/Electricity%20Capacity%20Report%202018_Final.pdf

[10] Please note it is not possible to calculate a true separate average EFC for onshore and offshore wind separately as they are highly correlated.

As more and more wind is assumed to be eligible (onshore initially followed by offshore) and is subsequently successful in the CM auction, then the average EFC of that eligible subset of the overall wind fleet gradually increases in % terms (the solid yellow line). This is because as the CM eligible wind starts to constitute a greater proportion of the overall wind fleet, then it's share of the contribution of wind to security of supply is correspondingly larger. The earlier-added wind capacities to the GB system were the most valuable from a security of supply context, due to the non-linearity of wind's contribution to security of supply.

The increase in the average EFC of the CM-eligible wind capacity is very gradual indeed. It takes an addition of ~8 GW of CM eligible wind before the collective value of that group of wind resources in percentage terms is more than 1% different to the incremental EFC they are individually paid in the auctions. However, as demonstrated in the above graph it is most likely that this will take until the late 2020s before the market evolves to be anywhere near such a state and justify any different approach. It is for this reason that an incremental EFC approach is likely to be robust as a de-rating factor approach for ALL wind until CM delivery years likely well into in the mid-late 2020s.

Summary and recommendation

We acknowledge that the question raised by respondents is a valid and meaningful one. The qualitative arguments outlined above, along with the additional quantitative modelling results support our proposed direction to use an incremental EFC approach for the wind and solar PV CM de-rating factors for the foreseeable future. Our proposed approach has also the support of the independent Panel of Technical Experts, and indeed independent academic consultants from the University of Edinburgh.

We had already identified this area as a potential topic for future work and we will keep the issue under observation.

3.2 Power Curves for larger turbines and update process

We reviewed and updated the wind power curves for onshore and offshore wind to support the calculation of winds contribution to security of supply. Our plan is to continue reviewing these curves on an annual basis as more data becomes available for different sized turbines both on and offshore.

Several respondents requested additional detail on the process and, in particular, which wind farms and turbine sizes were used in the calculation. Further information on our approach is discussed below, along with a list of the wind farms used in the study and their respective turbine sizes.

Half-hourly metered output and average wind speed data from a sample of transmission connected wind farms for winter 2017/18 was used in the analysis. The period covered spanned 1 November 2017 to 31 March 2018 and included the "Beast from the East".

A range of wind farms was selected to ensure that the sample was representative of various turbine make/models and turbine sizes. We first examined data from the larger and newer turbines (e.g. 7 or 8MW turbines for offshore wind), which are the size most likely to be connected in the future. However, the data were of limited use and was subsequently omitted from the wind power curves model. We will continue to review the value of this data for all future updates of the wind power curves.

The metered data used includes outages and breakdowns, which may be different to manufacturer's power curves. Similar metered data can be found on the BM Reports website[11]. The wind speed data are averaged for each half hour, while manufacturers' wind data are instantaneous. Further, the manufacturers' power curves do not consider the impact of the neighbouring wind turbines and the associated wake effects. We are not permitted to share the wind speed data due to a data confidentiality agreement with the Met Office, who is our weather data service provider. However, this data is available from them at a cost.

[11] See https://www.bmreports.com/bmrs/?q=actgenration/actualgeneration

Each wind farm was analysed individually and any obvious meeting errors or outliers were removed and an optimisation tool was used to fit an S-curve through the data points.

$$Load\ Factor = \frac{A}{1 + Be^{-C.ws}} - D$$

where ws = wind speed

A, B, C and D are parameters, which characterise the model.

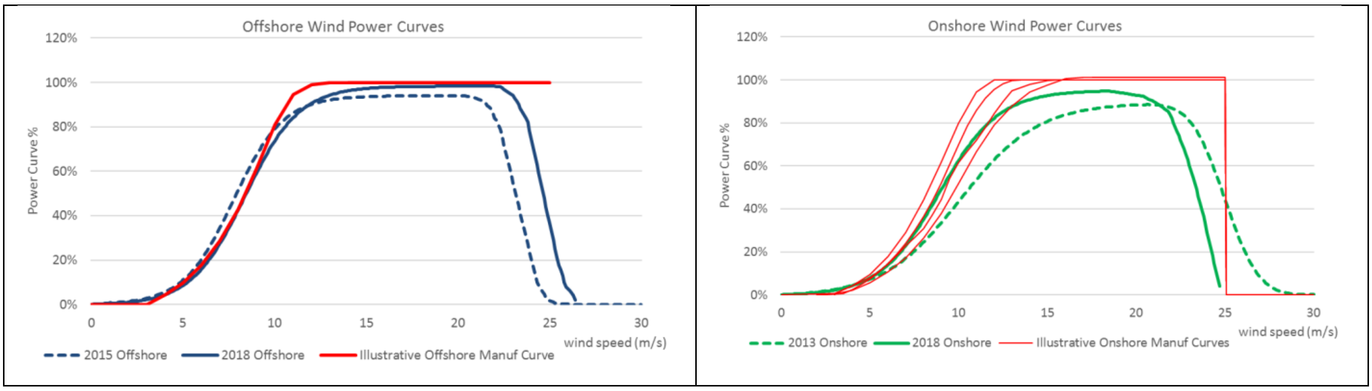
Note: The S-curve does not fit the cut-offs for wind power curves, which were estimated from the cleansed data.

All the offshore power curves were averaged by turbine sizes to determine the possibility of developing separate power curves for small and large offshore turbines. However, there were minimal differences thus we recommended to retain the use of one wind curve for offshore wind farms. All the wind farms that passed validation were combined to produce one single offshore power curve. A similar process for onshore wind resulted in the same recommendation of a single onshore wind power curve. We will continue to review this for future power curve updates as the larger wind turbines are installed.

18 offshore datasets were analysed, of which 12 datasets were used to derive the wind power curve and six wind farms were analysed but excluded due to insufficient or poor quality data. Forty onshore datasets were analysed, of which 18 wind farms were used to derive the wind power curve and 22 wind farms were analysed but excluded due to insufficient or poor quality data.

The following two charts show the latest offshore and onshore wind power curves compared to the previous curves and illustrative manufacturers' power curves. It can be observed that the 2018 curves align better with the illustrative manufacturers' curves compared to the 2015 curves for wind speeds of up to 10m/s.

Figure 3: Power curves for offshore and onshore wind



An important observation is that at low wind speeds the curves align well and this is the area of the curve that will have the biggest impact on the de-rating factors, as with increasing penetration of wind, system stress events are more likely to occur at times of low wind output.

Table 2: Wind farms analysed for the offshore wind power curve

Site Name	Turbine Size (MW)	No. of Turbines	Installed Capacity (MW)
Gunfleet Sands 1	3.6	48	172.8
Gunfleet Sands 2			
Dudgeon (4 units)	6	67	402
Gwynt Y Mor (4 units)	3.6	160	576
Lincs	3.6	75	270
Lincs 2			
London Array Phase One (4 units)	3.6	175	630
Thanet	3	100	300
Thanet 2			
Westermost Rough	6	35	210
Ormonde	5	30	150
Walney 2	3.6	51	183.6

Table 3: Wind farms analysed for the onshore wind power curve

Wind Farm Site Name	Turbine Size (MW)	No. of Turbines	Installed Capacity (MW)
Pen y Cymoedd	3	76	228
An Suidhe	0.8	23	19.3
Baillie Wind farm - Bardnaheigh Farm	2.5	21	52.5
Beinneun	3.4	25	85
Boyndie Airfield (Community Share)	2	7	14
Crystal Rig II	2.3	51	117.3
Dummuie	1.75	7	12.25
Fallago Rig	3	48	144
Galawhistle	3	22	66
Kilgallioch (Arecleoch Phase 2)	2.5	96	239
Mid Hill 1	2.3	25	57.5
Moy Estate	3.3	20	66
Strathy North	2.05	33	67.65
A'Chruach (Resubmission)	2.05	21	43.05
Airies	2.85	14	39.9
Andershaw	3.3	11	36.3
Hadyard Hill	2.3	52	119.6
Harburnhead	2.35	22	51.7

3.3 Regional onshore wind de-rating factors

Several respondents suggested the addition of sub divisions for onshore wind de-rating factors due to variations in regional wind conditions. We understand that this appears a sensible suggestion but note that it would require further analysis to ascertain fully whether higher load factors seen over a year translate into higher de-rating factors at periods close to or at times of system stress i.e. is the wind stronger at times of stress or just more frequent across the year.

Currently the CM rules would not allow such sub divisions as the CM is non-locational. If a wind farm could prequalify in a high de-rating sub division, secure a contract and then move location it could retain the higher de-rating. Consequently, if a new regional sub division was created for onshore wind then that loop hole would need to be closed to protect the consumer from under procurement in the CM.

In addition, consideration would need to be given on practical grounds as to how many sub divisions could be modelled due to time and complexity constraints. However, this can be considered as a potential development project for the next phase starting in the late summer / early autumn 2019.

3.4 Methodology consultations

As part of the existing ECR process, each year we consult on the method for calculating technology de-rating factors for the CM. In addition, for any new technology to the CM we run an industry consultation process which has so far involved an industry event and a written consultation.

For both, but particularly the latter, we engage extensively with our academic advisors, BEIS' Panel of Technical Experts and where appropriate benchmark our approach to other capacity markets around the world. This ensures our approach is fit for purpose and has been endorsed by independent experts which should give industry confidence that the method is robust given the data that is available.

We continually review our methodologies and look to enhance them as more data becomes available. However, technology de-rating factors need to be evidence-based and consequently, this makes it problematic when new technologies or designs come along as it will take time for operational data to become available.

3.5 Policy questions/issues out of scope

Several policy questions were raised in the consultation responses received. While out of scope for this technical consultation, we do recognise that the questions are valid and should be considered as part of the wider review of the CM, whether as part of the 5-year review or through the regular rules consultation. Consequently, any policy-related questions have been passed to BEIS and Ofgem for them to progress accordingly. As an indication, the policy questions raised covered topics such as the role of flexibility, hybrid de-rating factors, the performance regime and renewables being allowed to enter the CM, amongst others.

3.6 Potential future work programme

The consultation responses identified several potential development projects which will be considered for prioritisation as part of our annual development plan later in the year. These include:

- Interaction of technologies (discussed as part of methodology chapter)
- Hybrid de-rating factors where there is a connection constraint
- Regional de-rating factor analysis of wind
- Potential new onshore wind sub-division for the new larger wind turbines (could offshore power curves for similar sized turbines be utilised?)
- Long term (mid 2020s) review of appropriateness of using incremental de-rating factors once >10GW of wind has left the RO support mechanism

4. Conclusions and Next Steps

4.1 Conclusions

We observed broad alignment with our view on the underpinning methodology and suggested adoption of separate technology sub-categories for onshore and offshore wind, with incremental EFCs and EEU as the basis for the de-rating factors for renewables in the CM. The additional points raised around updating future power curves and the feasibility of introducing regional sub-divisions are recognised as valid and as such will be considered as part of our ongoing development programme.

In light of comments we feel our proposed methodology is, on the whole, supported and validated by industry and as such we continue to believe that the proposed methodology is appropriate for calculating de-rating factors for renewables. Thus, we will not be making any significant material changes to the methodology because of the consultation. Rather as part of our annual development process we will review and enhance our methods as more data become available and additional insight on technology operating regimes is gained.

4.2 Next Steps

In response to the consultation and as part of our planned work activities we will undertake the following:

- Submit to BEIS and Ofgem those questions which related to policy and the CM rules - March 2019

- Update the wind and solar de-rating factors for 2020/21, 2022/23 & 2023/24, using the latest MERRA data - including the “Beast from the East” period - and the draft 2019 Base Case view on future installed capacities - March 2019

- If renewables become eligible to participate in forthcoming auctions, then the updated wind and solar de-rating factors (reference above) will be published in the associated ECR and auction guidelines

- Produce the Electricity Capacity Report for 2019, which will contain a recommendation on the level of capacity to secure through the various auctions - submit 31 May 2019 and publish early July 2019

- Industry consultation on the methodologies for calculating technology de-rating factors, as part of the CM process – July 2019

- Work with BEIS and Ofgem to agree which development projects will be taken forward - Summer / Autumn 2019

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