Department for
Business, Energy
& Industrial Strategy

Capacity Market 2021 Call for Evidence: Summary of Responses

Improving delivery assurance and early action to align with net zero

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Executive Summary

On 26 July 2021, the government issued a Call for Evidence to seek stakeholder views on how to improve delivery assurance in the Capacity Market and on potential early actions to better align the Capacity Market with the achievement of net zero targets. The range of policy considerations included:

- Introducing a definition of ‘low carbon capacity’ via a new emissions threshold.
- Changing the eligibility criteria for multi-year capacity agreements to address the risk of locking carbon intensive generation into the Capacity Market.
- Removing barriers to participation for projects with long build times which may be unable to deliver in the four-year period from auction to first delivery year.
- Changing auction design to better enable low carbon capacity to compete in the Capacity Market.
- Strengthening the Capacity Market’s penalty regime to deter non-delivery in a System Stress Event.
- Introducing a new test to determine capacity’s connection to the grid.
- Enabling any remaining capacity obligation of a terminated Capacity Market Unit to be reauctioned by a third party.
- Reviewing the use of de-rating factors to better assess the reliability of generation, particularly end-of-life capacity.

The Call for Evidence also signalled the beginning of government’s engagement on the Capacity Market’s next statutory review (the Ten-year Review) to examine its performance against its core objectives. Finally, the Call for Evidence set out policy options for accounting for cross-border electricity flows in the Capacity Market now that the UK is no longer required to implement direct cross-border participation following EU Exit.

The Call for Evidence closed on 1 November 2021 and received 49 responses from a range of stakeholders. This document summarises the responses and sets out anticipated next steps.

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1. Introduction

1.1 Background to the 2021 Call for Evidence

In 2019, the Five-year Review of the Capacity Market concluded that it had been successful in meeting its core objectives: to ensure security of electricity supply, to do so at the least possible cost to consumers, and to avoid unintended design consequences, including by complementing the wider decarbonisation agenda.[1] The Call for Evidence published in July 2021 recognised that the context in which the Capacity Market operates continues to evolve, and that it may be necessary to make design changes to ensure the Capacity Market continues to meet its objectives during the transition to net zero.

As noted in the introduction to the Call for Evidence, the Capacity Market's design needs to be re-examined in light of the government's accelerated net zero ambitions. At the time of publication, the government's targets included reaching net zero by 2050 and achieving a 78% reduction in carbon emissions across the economy (relative to 1990 levels) by 2035.[2] More recently, the government announced its ambition to fully decarbonise Great Britain's power system by 2035, subject to security of supply.[3]

These targets present a range of opportunities and challenges for the Capacity Market. Firstly, we need to consider whether the Capacity Market's support for investment in new and existing capacity is consistent with the timely decarbonisation of the power sector. This includes examining whether the Capacity Market's design can support investment in low carbon capacity, and whether the current design risks locking carbon intensive capacity into the electricity system. Policy considerations to address these questions were presented in Chapter 2 of the Call for Evidence under the heading 'early action to align with net zero'.

Secondly, a range of ongoing and anticipated changes in the electricity mix – alongside increased electrification in various sectors of the economy – mean that we need to consider how to improve assurance that capacity secured at auction will deliver in times of system stress. During the next decade, we expect to see rising electricity demand (for example, in response to the electrification of heating and transport), the retirement of a significant amount of existing capacity (including older nuclear and gas plant, and all coal-fired power stations), and an increasing proportion of intermittent and inflexible renewable generation on the system. Moreover, the National Grid Electricity System Operator (NGESO) has limited visibility of the growing proportion of distribution-connected capacity on the grid, which can make it difficult for the NGESO to assess the risk of potential system stress events. A range of short to medium term options for achieving greater assurance that capacity is sufficiently incentivised to deliver

[1] https://www.gov.uk/government/publications/capacity-market-5-year-review-2014-to-2019
[2] https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035
[3] https://www.gov.uk/government/publications/net-zero-strategy

against its obligations were presented in Chapter 3 of the Call for Evidence under the heading ‘improving delivery assurance’.

The design changes considered in Chapters 2 and 3 of the Call for Evidence represent only part of the longer-term work needed to ensure the Capacity Market remains appropriate as a security of supply mechanism in a net zero context. Hence, the Call for Evidence also marked the beginning of the government’s engagement on the next five-year statutory review of the Capacity Market (the Ten-year Review), which is due for publication by summer 2024. This document will assess the Capacity Market’s performance against its core objectives, as well as considering how it has supported the decarbonisation of the power sector. Chapter 4 of the Call for Evidence sought stakeholders’ initial views on the Capacity Market’s performance and on potential areas of focus for future market design changes.

More recently, in April 2022 the British Energy Security Strategy announced the government’s intention to undertake a comprehensive Review of Electricity Market Arrangements (REMA) in Great Britain, with high-level options for reform set out in summer 2022.[4] Some of the design areas considered in Chapter 4 of the Call for Evidence may be examined further via the REMA project in consultation with stakeholders.

Finally, the Call for Evidence acknowledged the changing context for cross-border participation in the Capacity Market. The government had previously been taking steps to implement direct cross-border participation in the Capacity Market, in line with the requirements under the EU Electricity Regulation 2019 (which came into force on 1 January 2020). However, following EU Exit and the end of the Transition Period, the government can now consider alternative timelines and approaches for accounting for cross-border flows in the Capacity Market. Chapter 5 of the Call for Evidence sought stakeholder views on future policy options for cross-border participation, including a direct approach, the current indirect model involving the participation of interconnectors, and an approach focusing on domestic capacity only.

1.2 Considerations set out in the Call for Evidence

The Call for Evidence posed 33 questions under the following headings:

Early action to align the Capacity Market with net zero (questions 1-17) sought views on potential design changes including:

- Whether a definition of ‘low carbon capacity’ should be introduced, and how this definition should be determined.
- Amending the eligibility criteria for multi-year capacity agreements, including introducing an emissions threshold for accessing the longest agreements (up to 15 years), offering shorter multi-year agreements to carbon intensive capacity to ensure security of supply, reviewing the Capacity Market’s capital expenditure thresholds, amending the 77 month

[4] https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy

window for new build Capacity Market Units (CMUs) to spend their capital expenditure, and removing the Extended Years Criteria.

- Introducing a 'Declared Later Delivery Year' for low carbon technologies with long build times (such as Pumped Storage Hydropower) to improve their ability to participate in the Capacity Market.
- Changing auction design to better support net zero ambitions, including the introduction of a split T-4 auction design between high and low carbon capacity, changes to the function of the Price Taker Threshold, and changes to the function of the Net Welfare Algorithm.

Improving delivery assurance in the Capacity Market (questions 18-28) sought views on potential design changes including:

- Strengthening non-delivery penalties by changing the figure used in calculating the penalty rate, changing the penalty caps, introducing a 'stress event cap', changing credit cover arrangements, introducing new non-financial penalties, and implementing an alternative penalty regime. The Call for Evidence also sought views on improving the coordination of capacity in a System Stress Event.
- Introducing a Connection Capacity Test in line with recommendations from Ofgem, including considerations on how this test could be applied to wind and solar CMUs, distribution-connected CMUs, and co-located CMUs, and the appropriate timing for such a test.
- Enabling a third party to re-auction any remaining capacity obligation associated with a CMU that has been terminated during the delivery year, or between a capacity auction and the start of the relevant delivery year.
- Reviewing de-rating factors, with a focus on the potential for reduced reliability in end-of-life plant.

Future Capacity Market design (questions 29-31) sought views on:

- How the Capacity Market has performed since its implementation, based on stakeholders' experiences.
- Whether there is a continuing need for a mechanism to address system adequacy, for market intervention from government to address electricity security, and whether the Capacity Market (or any alternative future mechanism) should address wider system services.
- Whether stakeholders could outline any alternative mechanisms to better address current and future electricity security needs.

Accounting for cross-border flows in the GB Capacity Market (questions 32-33) considered:

- Whether the government should continue to pursue the ambition of implementing direct cross-border participation, and if not, how the security of supply contribution of cross-border flows can best be accounted for in target capacity calculations.
- Which approach to accounting for cross-border flows has the most merit: a direct approach, the current indirect approach involving interconnector participation, or an alternative approach focusing on domestic capacity.

2. Responses Received and Next Steps

The Call for Evidence was originally open for responses from 26 July 2021 until 18 October 2021. The deadline was later extended to 1 November 2021 to allow industry stakeholders to focus on dealing with the impacts of significant rises in wholesale gas and electricity prices during September and October 2021.

The Call for Evidence received 49 responses from a range of stakeholders, as follows:

- **Industry**, including capacity providers: 32 responses (65%). Of the industry respondents, 22 focus mainly on generation, 3 focus mainly on batteries and Demand Side Response (DSR), and 7 on interconnectors.
- **Public and commercial representation**, including trade associations, industry bodies, and charities: 11 responses (23%).
- **Research**, including academia and thinktanks: 2 responses (4%).
- **Delivery**, including government delivery partners: 2 responses (4%).
- **Finance**, including investment firms and organisations: 1 response (2%).
- **Private citizens**, 1 response (2%).

We would like to thank all respondents for the detailed and considered evidence they submitted. The responses are summarised according to key themes – early action to align with net zero (Chapter 2 of the Call for Evidence), improving delivery assurance (Chapter 3 of the Call for Evidence), future market design (Chapter 4 of the Call for Evidence), and cross-border participation (Chapter 5 of the Call for Evidence) – in the following chapters of this document.

BEIS will continue to draw on responses to the Call for Evidence while developing more detailed proposals on specific areas of potential Capacity Market design change. We aim to engage with stakeholders on high level proposals in summer 2022, and to publish a consultation setting out more detailed proposals later in 2022, with a view to considering implementing relevant changes ahead of the auction prequalification window opening in July 2023, parliamentary time allowing.

3. Summary of responses to Chapter 2 of the Call for Evidence - Early action to align with net zero

3.1 Defining 'low carbon capacity' in the Capacity Market

Questions on considerations in section 2.2 of the Call for Evidence

Question 1

Could 'low carbon capacity' in the context of the Capacity Market be defined in terms of an emissions limit? If so, what should form the basis of this limit – for example, would it be better to base a limit on carbon intensity or overall annual emissions, and what types of capacity should be captured by this emissions limit?

Question 2

Are there alternative approaches to defining low carbon capacity in the context of the Capacity Market? Please provide justifications.

Section 2.2 of the Call for Evidence sought stakeholders' views on defining 'low carbon capacity'. This definition could then be used to determine access to features such as the longest multi-year agreements (up to 15 years) or a declared later delivery year (see sections 3.2 and 3.3 below), both to help support the investment case in low carbon capacity, and to prevent carbon intensive capacity from being locked into the Capacity Market over the longer term.

Section 2.2 suggested that 'low carbon capacity' could be defined with reference to an emissions limit, which could be set at zero or almost zero carbon emissions, or at a higher level to enable emerging technologies (such as generation firing on a blend of hydrogen and natural gas) to be defined as 'low carbon capacity'. Stakeholders were also asked to consider whether an emissions limit based on carbon intensity (kgCO2/MWh) or one based on total annual emissions (kgCO2/annum) would be more appropriate, noting that more carbon intensive forms of generation (such as unabated gas-fired generation) could be able to meet a low carbon emissions limit based on total annual emissions if its running hours were limited to periods of high electricity demand or stress events.

Questions posed in section 2.2 of the Call for Evidence elicited 37 responses. Overall, 32 responses provided support for the idea of introducing a definition of 'low carbon capacity'. Of these responses, 14 indicated a preference for an emissions limit based on carbon intensity, 6 for an emissions limit based on total annual emissions, and 3 for the use of a combination of intensity and annual limits, while 2 responses indicated support without identifying a preferred approach. Three responses indicated support but emphasised significant reservations, and 4 responses suggested alternative approaches to achieving the policy aims set out in section 2.2. Five responses did not support the introduction of a definition of ‘low carbon capacity’.

Responses which preferred an emissions limit based on carbon intensity cautioned that basing any on total annual emissions could enable carbon intensive capacity with low running hours to be defined as ‘low carbon capacity’. Respondents expressed concern that this would allow carbon intensive capacity to access the low carbon section of a split T-4 auction design and/or long multi-year agreements, thereby contradicting the policy aims of bringing forward less carbon intensive capacity and of avoiding locking carbon intensive capacity into long agreements of up to 15 years. A small number of respondents also observed that meeting an emissions limit based on carbon intensity could prove challenging for generation using a blend of hydrogen and natural gas, although views were mixed as to whether this type of generation should be accommodated.

Responses which preferred a limit based on total annual emissions typically emphasised the need to ensure continued security of supply from carbon intensive capacity until low carbon alternatives are widely deployable. The use of an emissions limit based on total annual emissions was viewed as a better way of providing some continued revenue support to carbon intensive capacity as it transitions to running at lower load factors, and/or to primarily running in times of system stress. Some responses emphasised the need for a clearer strategic direction for phasing out unabated carbon intensive generation and for the deployment of low carbon alternatives.

Additionally, some responses suggested that an annual emissions limit could be decreased over time to encourage the transition to low carbon alternatives, and that government could look to replace an annual limit with an intensity-based limit once low carbon alternatives are deployable at scale. An annual emissions limit was also considered more suitable for hydrogen blend capacity. Finally, some responses observed that it could be more cost-effective to support carbon intensive capacity to run for a low number of hours within an agreed ‘carbon budget’ than to procure more expensive low carbon forms of dispatchable capacity which would similarly have low running hours.

Responses which favoured the parallel introduction of both types of emissions limits suggested that this approach would help to direct more investment at low carbon capacity via an intensity-based limit, while providing some continued revenue support for carbon intensive forms of firm and dispatchable capacity operating within an annual emissions limit to ensure security of supply (for example, as peaking plant). In line with responses preferring an annual emissions limit, some respondents who favoured running both forms of emissions limits in parallel recommended that the annual limit should be phased out in favour of an intensity-based limit once low carbon alternatives are deployable at scale, and that carbon intensive capacity running for restricted hours within an annual emissions limit should not be defined as ‘low carbon capacity’.

Responses which provided qualified support for the introduction of an emissions limit for defining low carbon capacity typically emphasised the need to ensure security of supply, as well as the reliance on system-wide developments in the power sector to enable a reduction in the carbon intensity of the capacity secured at auction. Some of these responses expressed concern that an annual emissions limit could prevent carbon intensive capacity from running in times of system stress if these running hours breached the annual emissions limit. One response also expressed the view that plant with a lower carbon intensity may produce more emissions if it is slow to cool and warm (and therefore runs for longer hours) than more flexible carbon intensive capacity which might be used for much shorter periods. Alternative approaches to defining 'low carbon capacity' included adopting a single system-wide approach to emissions limits (rather than introducing an additional limit specific to the Capacity Market), introducing an emissions 'bubble' allocated for the entire Capacity Market to be reduced on an annual basis, and applying a carbon intensity performance standard to suppliers' portfolios.

Regardless of which approach to setting an emissions limit was preferred, several responses requested that government should focus on alignment with the existing Environmental Permitting Regulations (EPR). Respondents suggested that any new emissions limit could be introduced under the EPR rather than the Capacity Market. They also commented on the need for a clear division of roles and responsibilities between the operation of the Capacity Market and the agencies responsible for the EPR in terms of implementing and monitoring compliance with any new emissions limit.

Responses which were not supportive of the approach set out in section 2.2 typically expressed the view that other system-wide mechanisms are better-placed to facilitate a reduction in carbon intensive capacity on the system – for example, that government should focus on the UK Emissions Trading Scheme and on carbon pricing to achieve this policy aim. Some responses also suggested that changes to the Capacity Market would be premature without greater clarity on the timelines for low carbon alternatives being deployed at scale. Additionally, some responses emphasised that the Capacity Market's primary purpose should continue to be ensuring security of supply rather than supporting the deployment of low carbon capacity, and that any design changes should be considered in light of their compatibility with this overriding objective.

3.2 Agreement lengths

Questions on considerations in section 2.3 of the Call for Evidence

Question 3

What are your views on the benefits or challenges of linking future long-term Capacity Market agreements to a new carbon emissions limit? Do you have any suggestions regarding an appropriate approach to setting such an emissions limit, and how could we best account for 'lower' rather than 'low' carbon technologies in determining eligibility for multi-year agreements?

Question 4

Is it necessary and appropriate for carbon intensive generation to continue to access shorter multi-year agreements, until such a time as low carbon dispatchable generation is more widely available?

Question 5

Would you expect these suggested changes to agreement lengths to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance? If so, how? Can you suggest any alternative approaches to ensuring agreement lengths offered in the Capacity Market are consistent with the delivery of net zero targets?

Question 6

Is it still appropriate to maintain the link between capital expenditure thresholds and multi-year agreements? If not, what other criteria could we consider using to assess eligibility for multi-year agreements (other than the new lower emissions limit discussed in section 2.3.2.1)?

Question 7

Should we revise the applicable capital expenditure thresholds? If so, what data could we base them on, and do we still need to have two different thresholds? Should low carbon DSR be able to access shorter multi-year agreements on the basis of emissions limits rather than capital expenditure thresholds?

Question 8

Should we review the 77 month window for new builds?

Question 9

What are the benefits of maintaining the Extended Years criteria?

3.2.1 Eligibility for multi-year agreements

Section 2.3.2 of the Call for Evidence considered how to ensure that multi-year Capacity Market agreements are consistent both with the objective of supporting investment in new and existing capacity to ensure security of supply, and with the objective of enabling the timely decarbonisation of the power sector. Long multi-year agreements of up to 15 years (the longest available in the Capacity Market) have had the effect of ‘locking’ carbon intensive capacity into the Capacity Market into the 2040s. This presents not only decarbonisation risks but also security of supply risks – for example, if large amounts of carbon intensive capacity exited the market in future in response to changed costs and revenue flows as the transition to net zero progresses). By contrast, multi-year agreements of up to 15 years may help to support the investment case in low carbon capacity.

Hence, section 2.3.2 considered whether to limit eligibility for the longest available multi-year agreements to capacity which can be defined as 'low carbon capacity' via the use of an emissions limit (see section 3.1 above), and whether capacity which has the potential to become 'low carbon' in future (such as hydrogen blend) should also be eligible for medium-length or long agreements. Additionally, section 2.3.2 sought stakeholder views on whether capacity such as unabated gas generation should be eligible for shorter multi-year agreements (for example, up to 5 years) to enable continued investment in this capacity for the purpose of security of supply as older generation retires, and in advance of low carbon alternatives becoming deployable at scale.

The question on limiting eligibility for longer multi-year agreements to low carbon capacity elicited 36 responses. Of these, 25 responses expressed support, 5 recognised the policy intent but suggested an alternative approach, and 6 opposed the approach set out in the Call for Evidence.

There were 15 responses which provided clear support for offering long multi-year agreements of up to 15 years to low carbon capacity only. These responses tended to suggest that offering long agreements for carbon intensive capacity is not compatible with net zero, and that changing the eligibility criteria for long agreements could send a strong signal to direct investment towards low carbon alternatives. Some responses observed that this change could also help to remove a perceived bias in the Capacity Market towards high carbon technologies.

Views were mixed as to how to approach the eligibility of 'lower carbon' capacity (such as hydrogen blend) for multi-year agreements. Some responses maintained that only zero or near-zero carbon technologies should be offered long multi-year agreements, based on a view that this approach would better direct investment towards genuinely low carbon capacity. However, other responses suggested that offering longer multi-year agreements to 'lower carbon' capacity could help to encourage investment in technologies respondents viewed as key for achieving net zero, such as hydrogen-fired generation. These responses suggested that any emissions limits used to determine eligibility for long agreements could initially be set more generously to accommodate 'lower carbon' technologies, before being tightened once low carbon technologies are deployable at scale. Some responses were also of the view that flexibility may be required for plants which have been retrofitted with carbon capture and storage (CCS) technology, given that such plants may not be optimised for running abatement equipment and would therefore be unlikely to perform as well as best-in-class new build CCS plant.

Several responses urged government to take into account unabated CMUs with existing multi-year agreements when considering changes to the Capacity Market to encourage investment in low carbon capacity, and asked whether any flexibility could be introduced such that these CMUs are able to abate once this becomes a viable option. Respondents also requested a clear direction over the future objectives of the Capacity Market – for example, whether its primary focus will be ensuring security of supply or supporting low carbon deployment. Responses suggested that a better understanding of the mix of high and low carbon capacity needed to meet the Capacity Market’s future objectives would give developers more certainty.

Respondents also observed that government should consider how the role of other support mechanisms, of Decarbonisation Readiness requirements, and of carbon pricing might interact with any changes made to agreement lengths. This message was echoed in responses providing qualified support for limiting eligibility for long agreements to low carbon capacity. Additionally, these responses emphasised the impact of wider uncertainty as to when abatement technologies would be available at scale. Some responses suggested that linking 15-year agreements to an annual emissions limit in the short-to-medium term might be a better solution for ensuring security of supply by supporting some carbon intensive capacity to come forward. Finally, some responses suggested that where capacity can demonstrate the feasibility of abatement and a readiness to abate, these factors could count towards access to longer multi-year agreements.

Alternative suggestions to the approach considered in the Call for Evidence included waiting until the Ten-year Review to assess changes to agreement lengths; focusing instead on incentivising growth in renewables and using the Contracts for Difference scheme as the main vehicle for promoting low carbon growth; and reducing Capacity Market payments relative to a CMU’s emissions.

Responses which opposed limiting eligibility for long multi-year agreements to low carbon capacity maintained that security of supply should be the Capacity Market’s primary focus, and that low carbon technologies are likely to seek investment from other mechanisms (for example, the Dispatchable Power Agreement). Some responses suggested that a strong carbon price should be sufficient to deter investment in new carbon intensive capacity, and expressed concern that changing eligibility for agreement lengths could lead to greater government intervention in the market and to government ‘picking technology winners and losers’.

The question on continuing to allow carbon intensive capacity to be eligible for shorter multi-year agreements (e.g., up to 5 years) to ensure security of supply elicited 37 responses. Of these,18 provided support, 3 recognised the policy intent but suggested an alternative approach, 7 opposed any changes to the current arrangements, 8 opposed offering multi-year agreements to carbon intensive capacity, and 1 response was neutral.

Of the 18 responses which provided support for continuing to offer shorter multi-year agreements to carbon intensive capacity, 12 responses emphasised the current role of unabated gas capacity in ensuring security of supply. However, they also expressed the view that these assets should not be locked into the Capacity Market over the longer term, and suggested that limiting multi-year agreement lengths for carbon intensive capacity could motivate investors to focus on low carbon alternatives. Moreover, several responses cautioned that if this approach was implemented, it would need to be phased out in a timely manner, because in the view of these respondents there is a risk that allowing carbon intensive capacity to secure multi-year agreements could encourage developers to slow their plans for abatement.

Some supportive responses urged government to provide greater clarity on the future of existing multi-year agreements for carbon intensive capacity, and to provide an overarching strategy on the future role of carbon intensive capacity as the power sector is decarbonised. As with responses to the question on limiting eligibility for the longest multi-year agreements to low carbon capacity, responses to this question also highlighted uncertainty over when low carbon alternatives will be deployable at scale, and suggested that a robust analysis of security of supply impacts should be carried out if changes to agreement lengths are taken forward.

A further 5 responses agreed with the overall policy intent but suggested that eligibility for shorter multi-year agreements could be linked to a CMU's ability to abate or to a firm commitment from a provider to abate. They suggested that this might include capacity providers committing to installing abatement technologies or to a significant reduction in annual emissions by the early 2030s or risk termination of their capacity agreement. Additionally, one response suggested that shorter multi-year agreements should only be available to 'lower' carbon capacity rather than carbon intensive capacity. Alternative approaches echoed those offered in response to the question on limiting eligibility for long agreements to low carbon capacity (for example, the suggestion of reducing Capacity Market payments relative to a CMU's emissions).

Responses which advocated for continuing to offer agreements of up to 15 years to carbon intensive capacity tended to emphasise what they considered to be a risk to security of supply from reducing support for unabated gas capacity. Responses also suggested that conditions could be placed on longer multi-year agreements for unabated gas capacity – for example, a suggested condition was that eligibility could be linked to meeting Decarbonisation Readiness requirements or to an obligation to switch to a low carbon fuel (such as hydrogen) once this option becomes available. Some responses urged the government to focus on refurbishing agreements for the abatement of carbon intensive CMUs, and to consider how to enable CMUs with existing long agreements to transfer to another support mechanism for abatement.

Responses which opposed offering multi-year agreements to carbon intensive capacity were of the view that this approach is not compatible with net zero, and suggested that government should consider when to stop offering Capacity Market agreements to carbon intensive capacity. These responses also expressed that continuing to offer even short multi-year agreements could send the wrong investment signals, and that government should instead focus on supporting investment in low carbon flexible capacity in the Capacity Market in order to ensure system security in a net zero context.

The Call for Evidence also sought stakeholders' views on whether and how the changes to agreement lengths discussed in section 2.3.2 would affect their decision to participate in the Capacity Market, their bidding behaviour, and the costs of and access to finance. Responses typically expressed the view that the changes discussed in section 2.3.2 could result in higher clearing prices in auctions if providers were to increase their bids in response to a reduction in agreement lengths (and therefore in Capacity Marker revenue) and to wider uncertainty regarding the future costs and revenue flows for carbon intensive capacity. However, some responses suggested that an increase in auction clearing prices might help to support some low carbon technologies in coming forward. Some respondents were of the view that greater clarity being provided on the future role of unabated gas (for example, anticipated running hours) could help to reduce investor uncertainty. Respondents whose current or future focus is already largely on low carbon projects indicated that changes to agreement lengths would not necessarily impact their approach to the Capacity Market, but some did suggest that the proposed changes to agreement lengths might help to support investment in new low carbon capacity.

3.2.2 Capital Expenditure Thresholds

Section 2.3.3 of the Call for Evidence sought views on the continued use of capital expenditure (CAPEX) thresholds to determine eligibility for multi-year agreements. The rationale for the current approach is that projects with a high level of capital expenditure might struggle to access finance without the benefit of a reliable long-term revenue stream from a multi-year Capacity Market agreement. The current thresholds (set in 2013 and linked to inflation) for accessing 3- and 15-year agreements were based on the cost of fitting selective catalytic reduction to a coal plant and the cost of a new build open cycle gas turbine respectively, and have not been revised since the Capacity Market's inception.

Section 2.3.3 sought stakeholder views on whether CAPEX thresholds should continue to be used in determining access to multi-year agreements, and, if so, whether the evidence underpinning these thresholds should be revised in light of the changing context in which the Capacity Market now operates (for example, whether the thresholds could instead be linked to the cost of decarbonising). These questions elicited 32 responses, of which 26 supported maintaining the CAPEX thresholds, with 24 of these responses also indicating support for reviewing the evidence base. Six responses suggested removing the CAPEX thresholds.

Responses which supported maintaining and reviewing the CAPEX thresholds expressed the view that these thresholds play an important role in ensuring that only projects with genuinely high capital expenditure requirements can access long agreements. Some responses also pointed to the role played by CAPEX thresholds in important Capacity Market checks, such as the Financial Commitment Milestone and Total Project Spend. Additionally, one response suggested that using alternative criteria for determining eligibility for long agreements – such as emissions limits – without also continuing to use CAPEX thresholds could enable CMUs to access longer agreements (and therefore longer revenue streams) than they really required, potentially resulting in poor value for money for consumers.

Suggested approaches to revising the CAPEX thresholds from respondents included undertaking analysis of whether and how the underlying costs and types of projects coming forward for longer agreements have changed, and then revising the thresholds as necessary to reflect relevant developments. Several responses observed that the data point currently underpinning the refurbishing threshold – the cost of fitting catalytic reduction to coal plant – is particularly outdated now that coal-fired generation is being phased out, and that the CAPEX thresholds should be made more relevant to the capacity types likely to contribute to achieving net zero targets. Some responses also suggested using the cost of retrofitting CCUS technology and/or retrofitting gas generators to blend hydrogen as potential data points for revised CAPEX thresholds, while one response was of the view that capacity seeking longer agreements should be able to demonstrate a link between their path to decarbonisation and their CAPEX requirements.

Responses which advocated for the removal of the CAPEX thresholds typically perceived these thresholds as representing a bias in the Capacity Market towards high CAPEX projects (particularly a bias in favour of generation at the expense of demand side response), and as a barrier to competition. Some of these responses suggested that only emissions limits should be used to determine access to multi-year agreements.

Section 2.3.3 also recognised that CAPEX thresholds might act as a barrier to participation for some technologies, particularly demand side response (DSR). Although eligible for multi-year agreements, DSR projects are generally unable to meet the current capital expenditure thresholds, which could prove to be a barrier to the expansion of low carbon DSR. Stakeholders were therefore asked to consider whether low carbon DSR capacity should be eligible for short multi-year agreements (for example, up to 3 years) where it does not meet the CAPEX thresholds but does meet a new emissions limit for defining ‘low carbon capacity’ (see section 3.1 above).

The question on whether low carbon DSR should be eligible for shorter multi-year agreements where it meets the emissions limit defining ‘low carbon capacity’ elicited 21 responses, 10 of which were supportive of this approach and 11 of which were opposed. Supportive responses tended to emphasise their view that DSR has a significant role to play in future security of supply, and that this change would also remove a perceived bias towards high CAPEX technologies. However, some responses cautioned that government should first assess the capital costs of bringing forward low carbon DSR to determine whether they are high enough for this capacity type to require greater revenue certainty. Some responses also suggested that government must ensure that only genuinely low carbon DSR capacity (rather than carbon intensive back-up generation) is able to access short multi-year agreements.

Those opposed to this change highlighted their view that enabling low carbon DSR to access multi-year agreements could lock consumers into higher costs for longer than necessary, particularly if this degree of revenue support is not genuinely required. Some responses also suggested that tailoring the approach to eligibility for multi-year agreements for specific technologies could create distortions; indeed, one response argued that such changes would detract from the Capacity Market’s technology neutrality, and described emissions limits and CAPEX thresholds as two distinct criteria which should not be interchangeable. Responses also cautioned that the sources of DSR being aggregated may not be very firm, and that government should consider the impact on security of supply.

Finally, the Call for Evidence also asked stakeholders to consider whether the 77 month window for new build Capacity Market Units (CMUs) to spend their capital expenditure should be reviewed. This question received 27 responses, of which 14 were supportive, 1 suggested the window should be removed, 11 opposed changes to the 77 month window, and 1 was neutral. Those supporting a review observed that government will need to ensure that this window is aligned with the project delivery timelines for long build time technologies (particularly if the option of taking a declared later delivery year is introduced – see section 3.3 below). Conversely, other responses expressed the view that the window may currently be excessively long for some projects. Responses also proposed that factors outside of developers' control, such as securing a grid connection, should be taken into account in any review.

Responses which opposed changes to the 77 month window expressed the view that there was no strong case for change, although some suggested that the window could be revisited in the longer term, particularly when new low carbon technologies are more widespread. The removal of the 77 month window was suggested in the context of one respondent's view that the Capacity Market should only offer one year agreements. Several responses, whether supportive of or opposed to a review, suggested that aligning the window for new builds with the window for refurbishing plant – in other words, running from auction results day until the start of the first delivery year – would not be a desirable change, as this would exclude costs incurred before auction results day for new builds.

3.2.3 Extended Years Criteria

The final design area considered in section 2.3.3 was the Extended Years Criteria (EYC). The purpose of the EYC is to provide assurance that Prospective Generating CMUs with agreements of four or more years contain equipment which is new (or 'as new' where rebuilt assets are concerned) and built to a high standard, and therefore likely to last for the full term of the agreement. The Call for Evidence recognised that the EYC may prove to be excessively burdensome for capacity providers and for the Delivery Body to evidence, that it is not possible to implement the EYC for all capacity types (such as DSR), and that there are already strong incentives (via the requirement to meet Satisfactory Performance Days or risk termination) for CMUs to maintain their capacity obligations throughout multi-year agreements, which can also be reduced if necessary through secondary trading.

Section 2.3.3 therefore asked stakeholders to consider the benefits of maintaining the EYC, while noting that the EYC addresses not only the operational status of a CMU but also provides confirmation that a CMU meets its associated combustion installation and efficiency standards, which may then need assurance through alternative means. This question elicited 23 responses, of which 13 supported the removal of the EYC, 3 suggested that the EYC should be reviewed, 6 opposed the removal of the EYC, and 1 was neutral.

Responses which supported the removal of the EYC emphasised their view that there are already strong delivery incentives and robust testing regimes in place, and that the EYC might not be necessary if the penalty regime was strengthened. Responses which supported a review of the EYC suggested that the government's focus should be on simplifying the process while ensuring that the policy intent of the EYC continues to be met. Some responses proposed that alternative safeguards would need to be established if the EYC are removed, and that the Substantial Completion Milestone report could be used as an alternative approach to ensuring certain key standards are met.

Responses which did not support the removal of the EYC tended to emphasise their view that the role of the EYC in demonstrating compliance with important standards, such as Best Available Technique Reference Documents (BREF) and combustion and installation standards. Some responses cautioned that establishing alternative assurance processes may prove to be equally expensive and administratively burdensome.

3.3 Projects with long build times

Questions on considerations in section 2.4 of the Call for Evidence

Question 10

What are your views on the introduction of a declared later delivery year as a way of addressing the challenges experienced by projects with long build times seeking to enter the Capacity Market? Would this affect your decision to participate in the Capacity Market, and if so, how? Are there other approaches we could take to removing barriers to participation for technologies and projects with long build times?

Question 11

Do you agree with our suggested approach to determining and verifying eligibility for a declared later delivery year? Are there other approaches we could consider?

Question 12

How can we best mitigate any security of supply risks arising from this approach? Can you identify any additional risks and/or disbenefits related to the introduction of a declared later delivery year?

Section 2.4 of the Call for Evidence considered options for addressing challenges identified through the Five-year Review of the Capacity Market for projects which may require longer build times than are provided for under the current design (including, but not limited to, pumped storage hydropower projects). New build CMUs have approximately four years from securing an agreement at auction to their first delivery year. If they are unable to meet this deadline, they may choose to activate the Long-Stop Date, such that they are permitted to meet the relevant completion requirement (the Substantial Completion Milestone or Minimum Completion Requirement) up to 12 months after the start of the first delivery year. However, in these circumstances CMUs will not be eligible for payments until the capacity agreement has taken effect. Hence, under the current design, capacity providers have approximately five years to deliver a New Build CMU, but they will experience a reduction in total agreement length and the forfeit of up to 12 months of Capacity Market revenues if they activate their Long-Stop Date.

Section 2.4 of the Call for Evidence sought views on whether the government should introduce the option for new build Generating CMUs to declare a later first delivery year than the start of the delivery year for the relevant T-4 auction (a 'declared later delivery year') in their prequalification application. This declared later delivery year could extend for up to 2 delivery years after the first delivery year mandated at the relevant T-4 auction, effectively allowing such projects up to 6 years to commence delivery without the loss of Capacity Market revenues. This option was not considered appropriate for introduction at T-1 auctions.

Additionally, Section 2.4 asked stakeholders for their views on how best to verify requests for a declared later delivery year. For example, the Call for Evidence suggested that the availability of this option could be subject to the provision of suitable evidence that such projects are not capable of delivering their capacity within four years, which would need to be verified by an Independent Technical Expert. Section 2.4 also suggested that capacity with a declared later delivery year should not be eligible to enter T-1 auctions or to enter into secondary trades prior to the commencement of their later first delivery year, and that any false declarations should result in termination. Finally, stakeholders were asked for their views on how best to mitigate any security of supply risks which could arise from this approach - for example, how any shortfall in capacity for the relevant first delivery year for a T-4 auction could be covered where some capacity providers had taken the option of a declared later delivery year.

Questions on the introduction of a declared later delivery year elicited 30 responses, of which 22 were broadly supportive. Of these 22 responses, 10 responses provided qualified support, including 5 responses which indicated that a declared later delivery year and/or other benefits potentially available to low carbon capacity (such as long multi-year agreements) should not be available to projects in receipt of any cap and floor mechanism for long duration electricity storage projects (considered by the government in a separate Call for Evidence published in July 2021),[5] and a further 3 responses which took the opposite view and suggested that both forms of support should be available to relevant CMUs. One respondent indicated a preference for a cap and floor mechanism instead of changes to the Capacity Market, while another response suggested that only critical technologies should be eligible for a declared later delivery year given the attendant security of supply risks. Responses from 8 stakeholders opposed the changes considered in section 2.4.

Supportive responses tended to emphasise the view that long duration electricity storage has a significant role to play in the future electricity system and can support the delivery of net zero targets. One response suggested that the option of having a declared later delivery year may

[5] https://www.gov.uk/government/consultations/facilitating-the-deployment-of-large-scale-and-long-duration-electricity-storage-call-for-evidence

be of benefit to other technologies, such as CCUS-enabled generation. These responses also typically agreed with the approaches set out in section 2.4 to determining eligibility.

Some supportive responses commented on the overlap between the considerations in section 2.4 and options in the government's Call for Evidence on facilitating the deployment of large-scale and long-duration electricity storage, and suggested that government should provide greater clarity as to which approach or approaches will be taken forward and how these will interact. One response indicated a strong preference for changes to be made to the Capacity Market's design rather than the introduction of a cap and floor mechanism, as they felt the latter approach could damage the investment case for short and medium duration electricity storage projects.

The potential for interactions between Capacity Market design changes and wider changes to support long duration electricity storage was also a common theme in responses which (although supportive in principle) expressed reservations about the approach considered in section 2.4. For example, 5 responses stated that CMUs which take up the option of a declared later delivery year should not be able to access any cap and floor mechanism, and vice versa, in order to avoid the risk of government over-subsidising some technologies and distorting competition in the Capacity Market. Some of these responses also argued that projects in receipt of support via a cap and floor mechanism should only be eligible for 1-year Capacity Market agreements, as considered in section 2.4.

One response observed that the introduction of a declared later delivery year could be useful for smaller projects with long build times but suggested that a cap and floor mechanism would be needed for large projects, as Capacity Market revenues alone would be insufficient to support investment in projects with such a high level of capital expenditure. The question of whether Capacity Market revenues alone would be sufficient to bring forward large projects with long build times also featured in responses which favoured enabling relevant CMUs to access both a declared later delivery year and any cap and floor mechanism, as well as a long multi-year capacity agreement. These responses were of the view that a combination of these measures would have the potential to reduce the overall costs of such projects.

Furthermore, some responses questioned the wisdom from a security of supply perspective of preventing CMUs with a declared later delivery year from participating in any T-1 auction prior to the commencement of their delayed first delivery year. Several responses were also of the view that section 2.4 was unclear on the question of whether refurbishing CMUs would also be eligible to access a declared later delivery year, and suggested that this option would be beneficial for large refurbishment projects with complex engineering requirements. Finally, some responses suggested that an important first step from government to support projects with long build times in the Capacity Market would be to ensure that T-4 auctions always occur 4 years ahead of the first delivery year, rather than roughly 3.5 years before the first delivery year as is currently the case.

Responses which opposed the introduction of a declared later delivery year argued that this change would mean that auction participants would no longer be competing on price for the same initial delivery year, which several respondents considered to be a fundamental principle of the Capacity Market. For example, a CMU with a declared later delivery year might set the clearing price for a T-4 auction but would not then deliver alongside the capacity it had set the price for; moreover, the price for the initial delivery year for capacity with a declared later delivery year could be lower than the price of the T-4 auction in which it competed. Respondents cautioned that such outcomes risk achieving poor value for money for consumers and urged the government to ensure participants in the Capacity Market are not receiving additional subsidies (for example, via a cap and floor mechanism). Some respondents suggested that technologies with long build times would be better supported outside the Capacity Market.

Section 2.4 elicited mixed views from stakeholders on how to tackle any security of supply risks arising from the introduction of a declared later delivery year, and no single approach was favoured across responses. Some responses considered securing replacement capacity via a separate low carbon auction (as discussed in sections 2.4 and 2.5 of the Call for Evidence) to be a viable option, but this was not a widely held view. One response suggested that limiting the amount of capacity which could secure a declared later delivery year in each T-4 auction might help to control the amount of capacity which would be unavailable during the relevant first delivery year for that auction, thereby minimising security of supply risks. Some responses suggested that replacement capacity could be secured at the T-1 auction for the relevant delivery year, but observed that this approach would prove challenging if insufficient replacement capacity came forward.

3.4 Alternative auction designs

Questions on considerations in section 2.5 of the Call for Evidence

Question 13

What are your views on the benefits and challenges of introducing an auction design splitting auctions between new build and refurbishing low carbon capacity and existing capacity? Would this affect your decision to participate in the Capacity Market or your bidding behaviour, and if so, how?

Question 14

What are your views on the potential split auction designs considered in sections 2.5.2 and 2.5.3? Are there alternative designs we should consider? And what approach could we take to setting targets for a separate low carbon auction?

Question 15

What are your views on expanding the scope of the Price Taker Threshold to potentially make it a price cap for Price Taker Capacity? Would this impact bidding behaviour? What changes to the Price Maker Memorandum might be necessary to ensure any changes to the Price Taker Threshold would be effective?

Question 16

What are your views on the potential benefits or challenges of amending the Net Welfare Algorithm to calculate to next lowest bid, rather than by the round floor price? Would this have an impact on bidding behaviour?

Question 17

How might the changes to auction design considered in section 2.5 interact with other design possibilities explored in Chapter Two concerning agreement lengths (2.3) and projects with long build times (2.4)?

Section 2.5 of the Call for Evidence explored possible changes to auction design to improve the ability of low carbon capacity to compete in the Capacity Market. Although the current auction design has resulted in liquid and competitive auctions, and has succeeded in delivering secure supplies at least cost to consumers, it has historically brought forward a significant proportion of carbon intensive capacity (such as unabated gas generation, which is generally the most cost-competitive new build technology). In turn, the low clearing prices resulting from the current auction design have proved insufficient to bring forward some technologies – including low carbon technologies – which have higher capital costs.

In light of these concerns, section 2.5 sought stakeholder views on splitting the T-4 auction between a dedicated auction for new build and refurbishing low carbon capacity, and a larger main auction for all other capacity. Section 2.5 considered two designs: holding a separate low carbon T-4 auction ahead of the main auction, or holding a single T-4 auction with multiple clearing prices. Questions on changing the T-4 auction design to create a split auction elicited 39 responses. Of these, 12 provided clear support for this change, 11 expressed some support but highlighted strong reservations, 13 opposed the change, and 3 responses were neutral.

Responses which were supportive of this change tended to emphasise the view that it could enable capacity to achieve higher clearing prices in the low carbon section of the auction, thereby incentivising low carbon technologies to compete in the Capacity Market. Responses which expressed support in principle but highlighted reservations typically focused on the complexities and risks involved in changing the Capacity Market's auction design. This includes the risk of volatile prices, low liquidity, increased complexity, and the overall difficulty in setting targets for a split T-4 auction, all of which could result in unintended consequences.

Moreover, some responses argued that other mechanisms may be better placed than the Capacity Market to bring forward low carbon capacity, and that there are alternative policy levers available (such as carbon pricing) for reducing the volumes of carbon intensive capacity procured at auctions. Several responses also suggested that, although the idea of a split auction has merit, the government first needs to clarify the future purpose and objectives of the

Capacity Market. These responses suggested that changes to auction design would be better considered as part of the Ten-year Review of the Capacity Market.

Alternative approaches included the suggestion that government should instead focus on interventions targeted at bringing forward flexible technologies such as batteries and DSR, or should consider implementing a cap on the volume of carbon intensive capacity eligible to enter Capacity Market auctions, which could be steadily reduced over time. A comment theme in neutral responses was that the changes to auction design considered in section 2.5 would not significantly impact their bidding behaviour or participation in the Capacity Market, but these responses did highlight similar questions to the responses discussed above (for example, how target-setting would be approached).

Responses which opposed this change typically emphasised similar concerns to those in the supportive responses outlined above. Additional concerns raised in these responses included risks to investor confidence in the Capacity Market due to increased uncertainty, and the risk of significantly increasing auction costs (and therefore also consumer costs) from potentially running less liquid and competitive auctions. Some responses also suggested that changes to auction design could lead to government planning the technology mix procured in the Capacity Market, contrary to the mechanism’s technology-neutral approach.

Stakeholders provided mixed views on the split auction design options considered in section 2.5. Responses which expressed clear support for changing the auction design were more likely to favour a separate low carbon auction held ahead of the main T-4 auction. Responses which expressed reservations about changing auction design typically preferred a single auction with multiple clearing prices as the better option for producing a liquid, competitive and cost-effective auction design.

In addition to considering split auction designs, section 2.5 explored changes to the function of the Price Taker Threshold (PTT), which determines the maximum price at which a Price Taker (typically an existing CMU) can withdraw from a Capacity Auction. Section 2.5 considered adapting the PTT to act as a price cap on Price Taker capacity in order to protect consumers from the risk of rising auction costs in future. The question on changing the function of the PTT elicited 23 responses. Of these responses, 6 were broadly supportive, 1 suggested reviewing the function of the PTT before making changes, and 1 was neutral. Fifteen responses opposed making changes to the PTT.

Responses which supported this change emphasised its potential to ensure the continued affordability of auctions. However, they suggested that more analysis would be needed to ensure this change could send the right market signals in terms of bringing forward more low carbon new build capacity. Responses also suggested that the level at which the PTT is set should be raised to ensure it can support investment in the maintenance of existing capacity which may not run as frequently in the future but may still be needed for security of supply.

Another common theme in supportive responses was the need for a more robust approach to the Price-Maker Memorandum to ensure participants would not be able to become Price Makers (and therefore avoid the PTT cap) without a strong justification. One response was supportive in principle but also expressed the view that the change considered to the PTT could constitute a move away from the current pay as clear auction model, and another response proposed that a wider review of the PTT is needed to reflect wider changes in market conditions and carbon reduction targets since the PTT was first set.

Responses which opposed using the PTT as a price cap on existing capacity tended to express the view that this change could increase bids from existing CMUs or disincentivise auction participation, which could in turn drive up auction costs, contrary to the stated policy aim. Several responses also observed that existing capacity which anticipates running at lower load factors in future might require a higher clearing price than would be provided for by the PTT in order to continue operating. Additionally, some respondents were concerned that changes to the PTT would introduce unnecessary levels of complexity and uncertainty into the Capacity Market's design. As with supportive responses, stakeholders who broadly opposed changes to the PTT emphasised perceived weaknesses in the Price Maker Memorandum process. Some responses expressed the view that changes to the PTT would seem to prejudice the outcome of auctions, and (as was flagged in supportive responses) could constitute a move away from a pay as clear auction.

In terms of managing rising auction costs, section 2.5 also asked stakeholders to consider whether government should remove the element of the Net Welfare Algorithm (NWA) which relies upon the clearing round floor price rather than on the penultimate highest exit bid, with the aim of reducing auction costs. The question on changes to the NWA elicited 20 responses. Of these responses, 6 provided clear support, 1 expressed support but highlighted reservations, 2 suggested more sustained policy work is needed in this area, and 3 proposed an alternative approach. Responses from 8 stakeholders opposed this change to the NWA.

Responses which supported this change to the NWA foregrounded the potential benefit of avoiding clearing prices being artificially set at the bidding floor price instead of the actual price, and generally did not believe that this change would have a detrimental impact on participants' bidding strategies. Some responses also suggested that this change would have the potential to reduce auction costs. However, responses which either provided qualified support or indicated the need for a more comprehensive review of the NWA observed that the change considered in section 2.5 would remove the protection of the round floor price, which could expose participants to greater uncertainty and discourage bids, thereby undermining potential cost savings. Alternative options suggested included requiring participants submit exit bids or moving to a sealed bid auction design.

Responses which opposed changes to the NWA tended to emphasise the risk of significant changes to bidding behaviour if participants no longer had access to the protection of the round floor price. Respondents suggested this could lead to price volatility, and might undermine any cost savings achieved by changing the NWA. In particular, some responses highlighted a view that this change would remove opportunities for participants to gain information throughout the auction that might influence their bidding strategy, which could reduce the efficiency of their bids. Some responses also considered this change to the NWA as a move towards a sealed bid auction, which they did not support.

4. Summary of responses to Chapter 3 of the Call for Evidence – Improving delivery assurance

4.1 Penalty regime

Questions on considerations in section 3.1

Question 18

What are your views on changing the figure used in calculating the penalty rate (for example, from 1/24 to 1/8 or 1/4)? Should the penalty rate be linked to the Value of Lost Load rather than the auction clearing price? Please provide supporting reasons/evidence.

Question 19

What are you views on the changes we consider in relation to the annual and monthly penalty caps?

Question 20

What are you views on the options we consider for improving the coordination of capacity during a stress event?

Question 21

Do you agree with the idea of introducing an additional Satisfactory Performance Day for CMUs that fail to deliver in a stress event?

Question 22

What are your views on the options we set out regarding the recovery of unpaid penalties?

Question 23

Would you expect any of these changes to the penalty regime to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance, and, if so, how?

Question 24

What are you views on the benefits and challenges of the alternative model for a penalty regime set out in section 3.1.5? Are there other models we should consider?

4.1.1 Penalty rate, penalty caps, and recovery of unpaid penalties

Section 3.1 of the Call for Evidence set out a range of options for strengthening the Capacity Market's penalty regime. This was identified as an area for change in the Five-year Review due to concerns that the current penalty regime may not adequately incentivise participants to deliver capacity in times of system stress. Over the coming decade, as electricity demand rises, and as older capacity retires or becomes less reliable, greater assurance is needed that the capacity secured at auction will deliver when required to in times of system stress. At the same time, it remains necessary to strike the right balance between risk and reward to incentivise continued participation in the Capacity Market.

One area of design change considered in section 3.1 included the calculation of the penalty rate, which is currently carried out in accordance with the following formula:

- *Penalty rate (expressed in £/MWh) = clearing price (£/MW) x 1/24*

Section 3.1 sought stakeholder views on whether to increase the figure used in the above formula from 1/24 to (for example) 1/8 or 1/4. Questions on changing this figure received 34 responses. Of these, 12 responses provided clear support, while 13 indicated support but also expressed reservations. Two responses indicated that the penalty rate should be re-examined as part of a wider review of the penalty regime, and 7 responses did not support this change.

Supportive responses suggested that increasing the figure used in calculating the penalty rate could help to drive appropriate behaviour from participants, both when bidding at auction and during stress events. Responses which offered qualified support for this change also observed the benefits of driving appropriate behaviour, but added that any changes to the penalty regime would need to account for non-delivery risks beyond a provider's control. Similarly, a common theme in responses which offered qualified support for this change to the penalty rate was that providers should be able to limit their exposure to risk by being able to secondary trade if they believe they may not deliver on their obligations. Several responses also suggested that BEIS should progress its previous proposal to require CMUs to register as Balancing Mechanism Units (BMUs) to ensure broader improvements to delivery assurance.

Responses which called for a wider review of the penalty regime suggested that penalties should be looked at in conjunction with the Capacity Market's termination regime, with the aim of ensuring that any changes made to strengthen penalties are proportionate and do not place additional administrative burdens on providers. Responses also proposed that BEIS should consider how any changes to the penalty regime may impact in different ways on the range of technologies participating in the Capacity Market.

Responses which opposed changes to the way the penalty rate is calculated typically highlighted the fact that no system stress event has occurred since the inception of the Capacity Market, and consequently argued that there is no evidence on the effectiveness of current non-delivery penalties. Moreover, some responses expressed the view that the real challenge for delivery assurance is a lack of visibility of some CMUs which do not currently participate in the Balancing Mechanism, and observed (as above) that BEIS should progress its previous proposal to require CMUs to register as BMUs rather than raising penalties for all participants in the Capacity Market, the majority of whom already have strong incentives to deliver in times of system stress. For these stakeholders, changes to the penalty regime should only be considered once the issue of capacity's visibility to the ESO has been solved. These respondents also emphasised their views on the need to improve secondary trading, and observed that changes to the penalty rate could result in higher auction clearing prices if providers factor the risk of increased exposure to penalties into their bids.

Stakeholders were also asked to comment on whether the penalty rate should continue to be linked to the auction clearing price, or whether an alternative measure – such as the Value of Lost Load (VoLL) – might be more appropriate. The majority of responses indicated that linking the penalty rate to VoLL would result in an unacceptably high level of risk for participants, although some responses suggested that linking the penalty rate to VoLL might provide a better measure of the impact of non-delivery during a stress event.

Whether supportive of linking the penalty rate to VoLL or not, several responses were of the view that there could be benefits to linking the penalty rate to a single known measure, particularly to address disparities between obligations for delivery years where there is a significant difference in clearing price between the relevant T-4 and T-1 auctions. By contrast, some responses argued that de-linking the penalty rate from the auction clearing price could introduce uncertainty and new risks for capacity providers, thereby disincentivising investment and participation in the Capacity Market.

Section 3.1 also considered changes to the annual penalty cap, which places an upper limit on the penalty amount of penalties a CMU can incur in any one delivery year. It is currently set at 100% of a CMU's capacity payments for the relevant delivery year. Section 3.1 considered whether this cap should be increased to between 101% and 150% to ensure that CMUs would risk losing more money than they received from the Capacity Market if they failed to deliver in times of system stress. Section 3.1 also considered whether the currently monthly cap – which is set at 200% of the monthly capacity payments payable to a CMU in the relevant month – should be replaced by a penalty cap for each stress event. This would avoid the risk of the current monthly cap preventing a CMU from being liable for the full amount of penalties if it failed to deliver during multiple stress events within a single month. Section 3.1 suggested that this new stress event cap could be set at 75% to 100% of a CMU's capacity payments for the relevant delivery year.

Questions on changing the design of penalty caps elicited 29 responses. Of these, 6 provided clear support for the changes considered in section 3.1, while a further 6 provided qualified support, 1 supported the introduction of a stress event cap only, 1 suggested a wider review of the penalty regime would be necessary, and 15 did not support any changes to the penalty caps. Supportive responses typically expressed the view that stronger caps could improve delivery assurance, although some responses cautioned that changes to the penalty caps could result in higher auction costs if participants factored an increased risk of exposure to substantial penalties into their bids. Increasing the annual cap to 110% was seen by some respondents as an appropriate balance for participants between risk and reward.

Some responses also suggested that government would need to strike the right balance between a strengthened penalty rate and stronger penalty caps – for example, a significantly stronger penalty rate could be balanced by an increase to the annual cap at the lower end of the 101-150% range suggested in the Call for Evidence. Moreover, several responses suggested that the introduction of a stress event cap appeared to be a more appropriate way of addressing non-delivery. Finally, one response observed that BEIS should consider whether the introduction of a strengthened penalty regime could be accompanied by a reduction in testing and prequalification requirements, given that greater delivery assurance would have been achieved via a reformed penalty regime.

Responses which provided qualified support for changes to the penalty caps suggested that any changes would need to be accompanied by improved arrangements for secondary trading and for calling System Stress Events, such that providers could limit their risk exposure. Several responses also observed that changes to the penalty caps could increase auction costs, and suggested that these changes could be detrimental to investor confidence (particularly for new low carbon technologies) due to increased risk exposure.

Additionally, some responses argued that the current penalty regime should continue to apply to existing capacity agreements, as providers with these agreements would not have the opportunity to bid into the Capacity Market at a higher price to reflect any increased risk from exposure to higher penalties. One response supported the introduction of a stress event cap only, but suggested that the 75%-100% range considered in the Call for Evidence was too high for a single event, and that 50% would be more appropriate. Finally, as with the changes to the penalty rate, one provider indicated that a wider and more holistic review of penalties would be preferable.

Stakeholder responses which opposed changes to the penalty caps typically contended that stronger penalty caps would create an unacceptable level of financial risk for providers, particularly for those bringing forward new build capacity. Some respondents felt that this increased risk would act as a deterrent to participation in the Capacity Market, which could result in less liquid and more costly auctions. Responses also observed that many CMUs already have strong incentives to respond to scarcity signals, and therefore do not require an additional signal via the Capacity Market’s penalty regime.

Finally, section 3.1 considered whether changes to the arrangements for recovering penalties in the event of non-payment are required. Currently, unpaid penalties are recovered from future capacity market payments. Section 3.1 considered whether capacity providers should instead be required to post and maintain credit cover, while noting that the government is at present minded to maintain the existing arrangements for recovering unpaid penalties.

Questions on this topic elicited 21 responses, 17 of which were supportive of continuing with the current arrangements for recovering unpaid penalties, although some responses suggested that a review might be required if the penalty regime undergoes significant changes. One response was neutral, and another response suggested (as with changes to the penalty rate and caps) that a wider review of the penalty regime is needed. The two responses which provided qualified support for changing the current arrangements were of the view that the requirement to post and maintain credit cover might improve delivery assurance by making providers factor in the risk of non-delivery when entering the Capacity Market, and that recovering unpaid penalties from future capacity payments can prove challenging given the variation in clearing prices for different delivery years.

4.1.2 Non-financial considerations

Section 3.1 considered options for change in additional to financial penalties, including whether CMUs which fail to deliver in a stress event should be required to undertake an additional Satisfactory Performance Day (SPD) within one or two months of the stress event. This question elicited 30 responses, of which 10 supported the introduction of an additional SPD. A further 3 responses called for a wider review of the penalty regime, while 17 responses did not support the introduction of an additional SPD.

Supportive responses tended to express the view that this change could improve delivery assurance, particularly by incentivising potentially unreliable CMUs to ensure they would be capable of delivery in a stress event. One response suggested holding this additional SPD during a core winter month, while others suggested that this requirement for an additional SPD would need to include a degree of flexibility for situations where a CMU may be struggling to fix an unexpected outage and may need a longer timescale to meet any additional SPD requirement.

Responses which did not support this change typically argued that the current SPD regime is sufficiently stringent, and that the requirement for an additional SPD would add unnecessary bureaucracy and complexity, with more negative impacts on technologies such as DSR. Respondents also observed that non-delivery in a stress event should be addressed via non-delivery penalties, not through the SPD testing regime. One response suggested an alternative approach under which an asset owner would be required to provide a director’s declaration confirming that the CMU in question would be able to meet its obligations for the remainder of the delivery year.

Section 3.1 also sought stakeholder views on other ways to limit Capacity Market participants’ exposure to the risk of incurring penalties, particularly under a strengthened penalty regime. This included government working with NGESO to improve the coordination of capacity in a system stress event by taking measures such as providing better information on the nature of a stress event before it commences, amendments to the calculation and/or sensitivities within the Capacity Market Notice, and the possible removal of the four-hour notice period.

Questions on this topic elicited 23 responses, of which the majority (17 responses) were supportive. Three responses suggested alternative approaches, and 3 did not support any changes. Supportive responses tended to emphasise the view that the provision of more information ahead of stress events would improve the delivery rate, particularly for CMUs which are not baseload generators and therefore need to prepare to increase generation or decrease demand. These responses also sought a review of ESO's processes around stress events and emphasised the need for improved communication. More broadly, improvements to arrangements for responding to system stress events were viewed as increasingly important in a system with a growing proportion of intermittent generation, storage and DSR, and one in which some capacity types transition to largely playing a peaking role.

The majority of responses did not support the removal of the four-hour notice period, although some responses suggested that a review of this notice period would be appropriate, especially because it was designed for technologies such a coal generation which require longer to warm, rather for the technology mix of the current Capacity Market. One response proposed that CMNs would provide a more useful signal to the market if their issuing was better aligned with other notices issued under the Grid Code. One response also observed that any CMN issued before midday excludes interconnector flows, which means that it could provide a misleading scarcity signal.

Alternative approaches suggested in responses included that BEIS should instead advance its earlier proposal to require all CMUs to be registered as Balancing Mechanism Units, which might influence any review of the arrangements for coordinating capacity in a system stress event. Another response indicated that the introduction of mock system stress events would be more useful in helping to predict potential delivery failures. Responses which were not supportive of making changes to improve the coordination of capacity in relation to a stress event suggested that a wider review of NGESO's management of the system is needed, particularly in light of a growing proportion of intermittent generation on the system, and that any changes considered within the context of the Capacity Market would therefore be too narrow.

4.1.3 Alternative penalty regime

The final consideration put forward in section 3.1 of the Call for Evidence was the potential to create an alternative penalty regime focusing on a simpler approach to applying penalties than the current regime. Under the alternative regime considered, providers would lose Capacity Market payments for a pre-determined number of months (e.g. two months) in the event of any non-delivery of capacity during a stress event. Section 3.1 noted that BEIS's preference is to retain and build on the current penalty regime rather than implement an alternative regime, and sought stakeholder views on the alternative regime described above. This question elicited 21 responses, of which 3 were supportive, 3 called for a wider review of the penalty regime, and 15 did not support the introduction of an alternative penalty regime involving the loss of Capacity Market payments.

Supportive responses tended to emphasise their agreement with the aim of simplifying the penalty regime, noting that a simpler regime would be easier to adapt as the Capacity Market's design evolves. These responses also observed the potential for the loss of payments to provide a stronger market signal to providers regarding the importance of fulfilling their obligations when called upon in a System Stress Event. One response suggested that a hybrid penalty regime could be introduced, in which under-delivery below a specific threshold during a System Stress Event would trigger the loss of capacity payments instead of the application of the mechanism's current non-delivery penalties. Both supportive responses and those which were opposed to the alternative regime emphasised the importance of implementing some form of tolerance, such that the loss of payments would not be triggered in cases where under-delivery was very minor, and where events beyond a provider's control had caused them to under-deliver against their obligation.

Responses which did not support the introduction of an alternative regime focused on the risk they perceived that the approach described in section 3.1 would struggle to account for partial delivery against an obligation, and might even disincentivise CMUs from delivering below their obligation if under-delivery and non-delivery were to trigger the same loss of capacity payments. Responses did suggest that a tolerance could be set to allow for a certain degree of under-delivery, but they observed that this already takes place via the de-rating process. They also expressed the view that setting such a tolerance might have a negative impact on security of supply if the Capacity Market's penalty regime allows all providers to under-deliver in a stress event by (for example) 10% without incurring any penalties.

Conversely, several responses argued that the alternative regime would be too harsh and could expose providers to an excessive degree of risk – particularly in the case of smaller capacity, intermittent capacity, capacity such as gas CMUs where supply chain issues can arise, and for newer technologies which might carry greater non-delivery risks until they become more mature. These responses observed that if providers factored increased risk into their auction bids, this could result in increased auction costs. Responses also suggested that a loss of payments could prevent providers from funding remedial work to CMUs following any failure to deliver, which might then prevent the CMU from being available in any subsequent stress event during the delivery year. Additionally, these responses expressed concern that providers could need to secondary trade parts of their obligations at short notice to manage the risk that any maintenance periods could coincide with a System Stress Event, and therefore with a potential loss of capacity payments. Responses also expressed concern that it might not be feasible to carry over payment suspensions into future delivery years because a CMU might not gain an agreement for the following delivery year, or may have changed its configuration.

Some responses which were not supportive of the alternative penalty regime argued that the approach of suspending payments for a set period would result in a penalty regime in which penalties no longer relate directly to the 'fault' – i.e., to the duration of non-delivery and to the under-delivered volume of capacity. Overall, responses which were not supportive of an alternative regime agreed that BEIS should focus on strengthening the current penalty regime, and also proposed that BEIS should consider pursuing other design changes – such as requiring CMUs to register as Balancing Mechanism Units – which respondents suggested would have a greater impact on improving delivery assurance in the Capacity Market.

4.2 Connection Capacity Test

Questions on considerations in section 3.2

Question 25

What are your views on appropriate testing arrangements for wind and solar CMUs, distribution connected CMUs, and co-located CMUs?

Question 26

Which is your preferred option of those proposed in section 3.2.5 relating to the timing of the connection capacity test? Are there alternative approaches we could consider?

Section 3.2 of the Call for Evidence explored the creation of a connection capacity test in light
Section 3.2 of the Call for Evidence explored the creation of a connection capacity test in light
of an earlier consultation from Ofgem, which examined the risk that Capacity Providers might overstate their connection capacity – the total export capacity available to a generation or interconnector CMU on the distribution or transmission network – in order to offset the reduction in capacity payments resulting from the application de-rating factors.

Ofgem proposed the introduction of a 'connection capacity test', under which Capacity Providers would be:

- Allowed to choose their connection capacity during prequalification, which should be no higher than the maximum a CMU can deliver and would be de-rated to form the bidding capacity of the CMU.
- Required to demonstrate their ability to reach the full nominated capacity by submitting the average of their three highest metered outputs during the 12-month period between April and March ahead of prequalification for the T-1 auction.
- If the connection capacity test is lower than the nominated capacity, a CMU's Capacity Obligation would be reduced proportionally to match the tested output (de-rated), resulting in a corresponding reduction in capacity payments. No changes would be made if the test result is equal to or higher than the nominated capacity, and providers would face a financial penalty if the test result fell below 97% of the nominated capacity. Stakeholders were broadly supportive of Ofgem's proposed approach, but because its implementation would require changes to the Principal Regulations, Ofgem requested BEIS's support in advancing these proposals.
- The Call for Evidence therefore sought stakeholder views on specific aspects of the implementation of a connection capacity test to support the development of consultation proposals, including:

- Appropriate arrangements for testing wind and solar CMUs to account for their variability in output – noting that an 80-90% threshold may be more appropriate than a 97% threshold when demonstrating the ability to meet their nominated capacity.
- Whether distribution-connected CMUs should be required to undertake a connection capacity test alongside transmission-connected CMUs.
- How to account for co-located CMUs – noting that any connection capacity test could be extended to require co-located CMUs to confirm that their combined connection capacity does not exceed the capacity of their connection point to the grid.
- The ideal timing of a connection capacity test – noting BEIS's preference for the test to be undertaken by the February ahead of prequalification for the T-1 auction.

Section 3.2 also noted that BEIS is not minded to change existing arrangements for new build and refurbishing CMUs. Questions on these considerations elicited 24 responses, of which 13 were broadly supportive, and 11 were not supportive of the considerations set out in section 3.2, or of the introduction of a connection capacity test in general.

Supportive responses tended to emphasise their view of the importance of basing connection capacity on actual metered data, of establishing appropriate systems to test the connection capacity of variable renewable CMUs, and of treating distribution-connected capacity in the same way as transmission-connected capacity. Some supportive responses emphasised the importance of industry involvement in setting any threshold for triggering a financial penalty where a CMU's connection capacity test falls below their nominated capacity, particularly to account for site-specific factors and for circumstances outside a provider's control (for example, an unplanned outage). Respondents also queried whether repeated testing of existing capacity should be required, and expressed the view that arrangements for testing connection capacity might prove burdensome for co-located CMUs, particularly where these CMUs are owned by different providers.

Views were mixed regarding the timing of the test. While some responses supported BEIS's preferred option of holding a connection capacity test by the February ahead of prequalification for the T-1 auction, one response proposed that the test should be held at prequalification, while another two responses stated that the test should take place as close to the relevant delivery year as possible, and one response suggested that the connection capacity test could be automated using existing data flows. Some responses made the general observation that the test should be timed such that there is an opportunity to cover any shortfall in capacity by adjusting the T-1 auction target.

One response expressed stronger reservations about BEIS's preferred timing for the test, noting that it could result in providers being penalised before they hold a Capacity Market contract and therefore before capacity payments have commenced. This response also highlighted that BEIS's preferred timing would coincide with a period when CMUs already holding T-4 auction agreements would not be permitted under the Rules to secondary trade to cover their position in the event of an unplanned outage.

Responses which did not support the considerations set out in section 3.2 were also unsupportive of the introduction of a connection capacity test, generally on the basis of their view that they have not seen sufficient evidence that providers are overstating their connection capacity to circumvent the impact of de-rating factors on capacity payments. These responses considered the introduction of a connection capacity test to be administratively burdensome and overly complex, and they were not convinced that it would improve delivery assurance. Responses suggested that strengthening the penalty regime or making changes to the Satisfactory Performance Day regime would create a stronger deterrent to overstating connection capacity.

4.3 Capacity obligations of CMUs that have been terminated

Questions on considerations in section 3.3

Question 27

Would it be beneficial for us to enable a third party (such as the Delivery Body) to re-auction capacity obligations in respect of CMUs that have been terminated during the delivery year, or between a capacity auction and the start of the relevant delivery year? If so, what are your views on the principles for such an arrangement (set out in section 3.3.2), and do you have any commercial considerations and/or concerns about the use of a third-party facilitator?

Section 3.3 of the Call for Evidence set out considerations regarding the risk that where a CMU is terminated without having secondary traded any or all of its capacity obligation, there is currently no mechanism for this capacity to be replaced, which could present a security of supply risk. To mitigate this risk, section 3.3 considered whether it would be beneficial to enable a third party (potentially the Delivery Body) to re-auction any remaining capacity obligation associated with a CMU that has been terminated during the delivery year, or between a capacity auction and the start of the relevant delivery year.

Section 3.3 offered an outline of this approach, noting that any re-auctioning process would need to include the communication of opportunities to bid (potentially on a pay as bid basis) for remaining capacity obligations, with capacity awarded to the lowest priced bids until the entirety of the obligation has been transferred. Where there are identical bids, the transferee with the lowest carbon emissions could be selected, and independent monitoring of the re-auctioning process would be required. In the case of a multi-year obligation, only the capacity obligation for the current delivery year would be auctioned, with the obligation for future years replaced through the relevant T-4 and T-1 auctions.

Section 3.3 further considered whether a minimum threshold for triggering this re-auctioning process would be needed, and whether a time limitation should be placed on trading to acknowledge that where the winter of the relevant delivery year has already passed, transferring the remainder of the obligation may not be necessary from a security of supply perspective and may not offer good value for money for consumers. Stakeholder views were also sought on alternative approaches to solving this challenge.

Questions on section 3.3 elicited 27 responses, of which 16 were broadly supportive of the suggested approach. Eight responses called for a wider review of secondary trading in the Capacity Market, and 3 responses did not support the approach considered in section 3.3. Supportive responses typically emphasised their views on the benefits of this approach in addressing security of supply risks arising from the loss of terminated capacity, and they tended to agree with the principles set out in section 3.3. Some responses, while supportive of the principle of seeking to replace capacity ‘lost’ in these circumstances, suggested that the process outlined in section 3.3 sounded more like a tender than an auction, and that such an approach should only be used in carefully limited circumstances to avoid adding further complexity to the Capacity Market. Some responses also offered views on suitable third parties to facilitate the re-auctioning process.

Responses which called for a wider review of secondary trading were sympathetic to the concerns explored in section 3.3, but suggested that wider improvements to the functioning of secondary trading in the Capacity Market would provide a more efficient solution than needing to create ‘mini-auctions’. These responses highlighted challenges with liquidity in the secondary trading market and with a lack of overall coordination for secondary trading, which some responses felt could be improved by the introduction of a platform to facilitate trades. These responses also proposed that changes to secondary trading should be considered holistically alongside potential changes to improve delivery assurance in the Capacity Market.

Responses which did not support the approach considered in section 3.3 questioned whether it would represent good value for money for consumers, particularly if transferees receive a higher clearing price than capacity competing at the T-1 and T-4 auctions for the relevant delivery year. These responses argued that stronger incentives could be established for CMUs to facilitate a secondary trade prior to termination – for example, the Rules could be changed to enable a reduction in termination fees where a CMU facing termination completes its own secondary trade.

4.4 De-rating factors

Questions on considerations in section 3.4

Question 28

In your view, do the current de-rating methodologies remain appropriate and reflect a CMU’s risk of non-delivery? If not, what alternative methodology could be applied and why? Please submit any evidence in support of your view.

Section 3.4 of the Call for Evidence examined de-rating factors, which determine the capacity obligation that can be secured at auction by a given technology class and set the expected level of contribution to security of supply during a stress event by technology type. Section 3.4 noted that de-rating factors may not be reflective of an individual CMU's non-delivery risk, which may fluctuate at different stages in a CMU's lifecycle – for example, more frequent maintenance cycles may be required as a CMU approaches the end of its operational life. An accurate assessment of non-delivery risk may also be hampered by a lack of data on the behaviour and capacity of specific sites, as is currently the case for embedded generation. As more capacity approaches the end of its operational life and the deployment of distributed generation continues rise, it is increasingly important to ensure de-rating factors provide an accurate assessment of capacity's ability to deliver in times of system stress.

Section 3.4 therefore sought stakeholder views on potential changes to the approach to de-rating factors in the Capacity Market. Ideas considered included allowing capacity providers to select their own de-rating factors (with the NGESO's calculated de-rating factors acting as an upper limit), which could allow providers to select de-rating factors reflective of a CMU's technical performance and non-delivery risk. Alternatively, the current de-rating methodology structure could be amended to account for specific challenges – for example, a methodology could be designed specifically for to end-of-life capacity, or to better reflect the availability of embedded generation. However, this approach would face considerable design and data challenges.

Questions on section 3.4 elicited 32 responses, of which 15 preferred an approach allowing capacity providers to select their own de-rating factors. Twelve responses argued for a broader review, with some suggesting alternative approaches. Three responses did not agree that de-rating factors should be reviewed, and 2 argued that de-rating factors should be abolished.

Responses which were supportive of allowing capacity providers to select their own de-rating factors tended to argue that capacity providers are best placed to quantify non-delivery risks specific to their CMUs. Several respondents suggested that this approach could be complemented by a strengthened penalty regime, and could be designed such that providers choose their de-rating factor from within a set range for each technology class. Several responses also expressed the view that end-of-life capacity is not necessarily at greater risk of non-delivery if it has been well-maintained.

Responses which called for a broader review typically agreed that changes may be needed to reflect the evolution of different technologies and to reflect the potential for greater non-delivery risk in end-of-life assets; however, they argued that a wider range of approaches than those explored in section 3.4 needed to be considered, and were of the view that improvements to delivery assurance should be explored in the round. Alternative approaches suggested included that BEIS should focus on specific technologies, including intermittent generation, interconnectors, and batteries. Several responses highlighted challenges with the use of historic operational data, and one response argued that BEIS should consider implementing a requirement for CMUs to be registered as Balancing Mechanism Units in order to solve challenges with the visibility of embedded generation.

Responses which favoured retaining the current approach to de-rating factors typically highlighted the difficulties in designing and implementing specific de-rating factors for end-of-life capacity. They also considered other features of the Capacity Market – including penalties, Satisfactory Performance Days, and secondary trading – more appropriate design areas for improving delivery assurance. Finally, respondents expressed concerns about the risk of increasing the complexity of the Capacity Market.

Responses which argued that de-rating factors should be abolished emphasised their views on the perceived difficulty in using broad de-rating factors to account for significant variations in specific units and operating regimes within a given technology class. One response suggested that the real issues to be addressed are the intermittency of renewable assets and the unpredictability of interconnector flows, while another argued that a strengthened penalty regime alone should be sufficient to deter providers from overstating their capacity.

5. Summary of responses to Chapter 4 of the Call for Evidence – Future market design

Questions on Chapter 4

Question 29

Do you have initial views based on your experience on the Capacity Market's performance since its implementation that we should consider?

Question 30

What are your initial views on the Capacity Market as a continuing mechanism to address system adequacy? Is there a need for continued market intervention by the government to address electricity security? And should the Capacity Market (or alternative electricity security mechanism) also address wider system services such as flexibility and stability?

Question 31

Are there alternatives to the Capacity Market that may meet our current or future electricity security needs better, that we should consider? Please provide evidence to support your views.

Chapter 4 of the Call for Evidence set out the government's intention to examine (as part of the Ten-year Review process) how the Capacity Market has met the additional criterion of 'net zero compatibility' alongside whether it has achieved its core objectives. It is important to note that since the Capacity Market was implemented in 2014, the GB electricity system has experienced substantial change, and will look significantly different to the present system at the end of this decade, which raises questions around the continuing need for the Capacity Market and its design. Most of GB's power supply will likely be derived from intermittent renewable capacity, which will need to be supplemented during periods of low renewable output by flexible and dispatchable capacity to ensure system stability and security of supply.

Questions 29 to 31 therefore asked stakeholders about their experience of the Capacity Market's performance since implementation; whether they believe there is a continued need for the Capacity Market and for government intervention to ensure security of supply; and whether they could suggest any alternatives mechanisms or approaches for ensuring security of supply.

Twenty-eight responses provided a view on the Capacity Market's performance since implementation. Although these were broadly positive, 26 responses referenced negative impacts and made suggestions for improvements. In particular, 7 responses directly referenced unintended consequences such as market distortion, high carbon asset lock-in, and the view that administrative burden of entering the Capacity Market creates barriers to participation and increases clearing costs. Conversely, one response suggested that the design of the Capacity Market has had the unintended consequence of low and uneconomic clearing prices, particularly due to generators cross-subsidising their bids across different revenue streams.

Several responses called for increased digitalisation of the Capacity Market to align with government's wider digitalisation ambitions. This was viewed as a way improving participation in the market by removing administrative barriers for smaller generators which lack the infrastructure to navigate the entry process. Some respondents observed that an additional benefit would be the ability to access formal settlement data without having to wait for the official settlement run flows.

Responses also expressed a desire for the Capacity Market to be better aligned with other regimes such as Contracts for Difference (CfD) and Dispatchable Power Agreement. For example, respondents suggested that such alignment could include the Capacity Market allowing capacity to exit and transition to a CfD contract, which respondents argued would create additional pathways to allow generators to implement low carbon capacity onto the system whilst reducing administrative burdens and the risk of penalties.

Some respondents were also of the view that the Capacity Market is fundamentally not designed for participation from portfolios of thousands, if not millions, of smaller assets. These respondents pointed to the prequalification process to support their view and observed that it is currently not possible to enter an Electric Vehicle portfolio into the Capacity Market. This is because in order to reach the minimum scale of 1 MW, a portfolio would need to have at least 350 cars (7 kW assumption) and up to 700 to respond reliably in times of system stress. It is currently not technically possible to have a Capacity Market Unit which contains more than 300 assets. This leads to capacity providers needing to enter a mixed asset portfolio, which results in different technology parameters and de-rating factors for the CMU to manage administratively.

Section 4.2.3 explored future market design and asked stakeholders to consider whether the Capacity Market is an appropriate continuing mechanism to address system adequacy and whether it, or an alternative electricity security system, could address wider system issues such as flexibility and stability. Further, it questioned whether there is a continued need for market intervention by the government to address electricity security.

There were 30 responses to this section, 28 of which were supportive of the Capacity Market continuing, with 11 suggesting adaptions to make the mechanism compatible with the future system needs, and 7 suggesting adaptions to align it with net zero. Several responses suggested that a technology-neutral Capacity Market and a simplified structure with increased digitalisation would create an agile and efficient mechanism.

Sixteen stakeholders responded to the question of whether there is a continued need for market intervention, with 15 believing continued intervention to be crucial for achieving system security. Conversely, one respondent argued that market intervention is a political matter of whether government thinks that markets can deliver. Another response viewed the Capacity Market as a market for a commodity that the power system needs, rather than a government intervention.

On the topic of widening the scope of the Capacity Market to address more than just adequacy of supply, 21 responses were submitted, of which 7 were in support of this and 11 were opposed. Of the 7 responses that supported widening the scope of the Capacity Market, flexibility and locational signalling were popular themes for expansion. Three of the 7 suggested that this expansion should be achieved by targeted support and removal of barriers for specific technologies, such as long-duration storage, rather than a direct procurement of wider system services. It was suggested that a complementary longer-term procurement strategy would be required alongside any expansion of the Capacity Market’s scope.

Of the 11 responses which opposed expanding the Capacity Market, 6 pointed out that we already have support mechanisms for low carbon capacity (such as the CfD and Dispatchable Power Agreement), and that the ESO should continue to lead on procurement of system services. They also observed that the Capacity Market’s current design could prove to be a barrier to diversifying the mechanism’s scope. Three respondents were supportive of a review of the value of including expanded services in the future.

In addition to redesign and review, one respondent observed that the Capacity Market was initially intended as a temporary measure to assist with security of supply and ensure an orderly transition to net zero. Given the expedition of net zero, this response called for the prioritisation of a redesign of the electricity wholesale market so that it both provides security of supply and supports an efficient and zero carbon electricity system. This vision was echoed by other respondents.

Section 4.2.3 also asked whether stakeholders could identify alternative mechanisms to the Capacity Market that may meet current or future electricity security needs and should be considered. Of 18 responses, only one was directly in favour of an alternative mechanism to address security of supply by way of a strategic reserve to serve adequacy requirements, in combination with a decentralised model such as a reliability obligation or option. However, it is important to note that whilst alternatives were not widely supported amongst responses, several respondents suggested the phase-out of the Capacity Market (or similar interventions) once it has supported the decarbonisation transition.

Other alternatives proposed were in line with options considered elsewhere in the Call for Evidence. For example, one response supported the introduction of a low carbon emissions limit within the Capacity Market and an approach limiting carbon intensive capacity to either short Capacity Market agreements, with procurement through a separate strategic reserve suggested as an alternative approach. The majority of responses were supportive of the Capacity Market being redesigned to provide continued security of supply whilst ensuring that high carbon assets are not unnecessarily locked into the system for the long term and that low carbon assets are prioritised.

As noted in the introduction to this document, the future direction of the Capacity Market and/or its replacement with an alternative mechanism are now being explored through the Review of Electricity Market Arrangements (REMA).

6. Summary of responses to Chapter 5 of the Call for Evidence – Cross-border participation

Questions on Chapter 5

Question 32

Should we continue to enable cross-border participation in the Capacity Market? If not, why not? In the absence of cross-border participation, how should target capacity calculations be altered to reflect the contribution of cross-border flows to security of supply?

Question 33

If the CM continues to enable cross-border participation, what should be the preferred approach to cross-border flows – enabling direct participation of foreign generation, or continue with the existing indirect cross-border participation model (via interconnectors)? Please provide evidence to support your views.

Chapter 5 of the Call for Evidence sought stakeholder views on how to address the changing context for accounting for cross-border flows in the Capacity Market. This chapter noted that, as a consequence of the UK's exit from the EU, the requirement under Article 26 of the EU Electricity Regulation to implement direct cross-border participation in the GB Capacity Market was no longer part of domestic law (having been revoked from retained EU law).[6] This chapter also observed that the arrangements required for implementing direct cross-border participation have not yet been fully established in the EU.

Consequently, the government can now consider a range of future options for accounting for cross-border electricity flows in the Capacity Market. This includes considering whether cross-border participation – both the current indirect model involving interconnectors, and a direct model involving non-domestic capacity participating in the GB Capacity Market – should be a feature of the Capacity Market. Stakeholders were asked to consider whether cross-border participation in any form should continue to be a feature of the Capacity Market, and, if so, which model of cross-border participation they preferred.

Questions on Chapter 5 elicited 39 responses, of which 14 preferred to retain the current indirect model and 11 preferred a direct cross-border participation model. Two responses

[6] See Regulation 7 and paragraph 25 to Schedule 4 of the Electricity and Gas (Internal Market and Network Codes) (Amendment etc.) (EU Exit) Regulations 2020, which fixed inoperabilities in retained EU law arising as result of EU Exit. Available at: https://www.legislation.gov.uk/ukdsi/2020/9780348209495/contents.

argued for maintaining the current indirect approach in the short term before moving to a direct model, 5 argued for an approach involving only domestic capacity competing in the GB Capacity Market, 5 argued for the immediate exclusion of interconnectors, and 2 responses were neutral. It is worth noting that regardless of their preferred approach to accounting for cross-border flows, the majority of responses argued that the government should not aim to make changes in the near term, and should instead observe developments on the continent and within GB's own capacity mix before implementing any new model.

A common view in responses which argued for retaining the current indirect model was that interconnectors make a valuable contribution to security of supply as well as providing value for money for consumers. Responses also argued that the stable revenue stream provided by the Capacity Market continues to play an important role in interconnector business models, and some responses contended that interconnector participation contributes to auction liquidity. Furthermore, some responses suggested that removing the ability of interconnectors to participate in the Capacity Market could negatively impact overall investment in cross-border infrastructure, which respondents argued would be at odds with the government's ambitions to ensure a secure and flexible energy supply in a net zero context.

The majority of responses which favoured the current indirect model did not dismiss the possibility or desirability of a direct model being implemented in future; however, they observed that a direct model would be complex to design and challenging to administer. Some responses, although supportive of continuing with the current indirect model, proposed a thorough review of interconnector de-rating factors to ensure they account for a wide range of non-delivery risks.

Responses which preferred a direct model typically maintained that implementing this model should not be a priority for the government. However, they argued that if cross-border participation is a policy goal for the GB Capacity Market, then a direct model would likely be fairer than an indirect model, providing that a level playing field regarding costs such as network charging could be established. Some responses considered a direct model to be more beneficial to security of supply because it would place a clear obligation on the capacity at the other end of an interconnector to be available in times of GB system stress. Moreover, some respondents were of the view that a direct model could help to prevent the offshoring of carbon emissions, since all capacity participating in the GB Capacity Market would be subject to the same emissions limits.

Again, responses emphasised the view that a direct model would be challenging to implement and could take a long time to become established. On that basis, some respondents considered that more immediate improvements to accounting for cross-border flows should be made in the short term. For some respondents, this included removing interconnector participation more rapidly; by contrast, other responses did not object to continued interconnector participation in the short term, but argued that the contribution interconnectors make both to security of supply and to value for money for consumers should be re-examined as a matter of priority, including a review of interconnector de-rating factors.

Responses which argued for a model including only domestic capacity argued that GB's energy security would be best served by a Capacity Market with a focus on bringing forward domestic capacity capable of reliable delivery during a stress event. While recognising the benefits of interconnection in terms of system operability, these respondents argued that interconnectors are not well-suited to providing system adequacy, and that the government's priority should be to bring forward more low carbon domestic capacity. Responses also emphasised the fact that interconnector participation was intended as a short-term measure to facilitate the implementation of direct cross-border participation, and argued that it should therefore be removed now that direct cross-border participation is no longer required. Respondents also expressed concerns that interconnector participation may be deterring investment in firm domestic capacity.

Some responses to Chapter 5 focused solely on expressing the view that interconnectors should not continue to be allowed to compete in the GB Capacity Market, particularly due to the perceived risk that interconnectors may not deliver capacity in times of system stress. These responses also tended to highlight a belief that interconnectors are being overcompensated by benefiting from a cap and floor regime alongside access to the Capacity Market, as well as being exempt from transmission charges. One respondent argued that interconnectors may be displacing firm domestic capacity in auctions to the detriment of GB's future electricity security.

This summary of responses is available from: www.gov.uk/beis

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