UK Government

Capacity Market: Call for evidence response on Hydrogen to Power and Interconnectors

Government Response

Department for Energy Security and Net Zero (2026)

Any enquiries regarding this publication should be sent to us at:
futureelectricitysecurity@energysecurity.gov.uk

Contents

1. Executive Summary

The security of electricity supply is vital to successfully achieving the Prime Minister's Clean Energy Superpower Mission and its key pillars of providing clean power by 2030 and accelerating the delivery of net zero by 2050.

The Capacity Market (CM) is at the heart of the government's strategy for ensuring security of electricity supply in Great Britain (GB). It was first introduced in 2014 as part of the Electricity Market Reform programme to support investment in capacity and deliver value for money for consumers. Existing and new build electricity capacity providers compete to obtain CM agreements under which they commit to deliver capacity when needed, in return for regular payments.

On 2 October 2025 the government published a Call for Evidence on Hydrogen to Power (H2P) and interconnectors.[1] This consisted of 20 questions:

- Questions 1 – 12 sought evidence to inform how H2P plants should be categorised within the CM
- Questions 13 – 20 sought views on the adjustment that the government applies to reflect the technical reliability of interconnectors when setting their de-rating factors

The Call for Evidence received 41 responses from a range of stakeholders. This document provides an overview of stakeholder views presented on the Call for Evidence topics, including any alternative suggestions put forward, and identifies next steps in policy development.

The government will take account of the feedback provided to questions 1 – 12 when making future policy decisions regarding H2P. We will undertake further policy development and engage with CM delivery bodies to develop a proposed approach to H2P participating in the CM. We intend to outline our proposals later this year.

After taking into consideration the responses to questions 13 – 20, the government will update the methodology used to calculate technical adjustments for interconnector de-rating factors for implementation ahead of the 2026 Prequalification window. For new and refurbishing interconnectors, the technical adjustment will be defined as the minimum of the availability range derived using the most recent SKM model, updated with any new engineering data,[2] or where there is little historic availability data, the technical characteristics of that interconnector. For existing interconnectors with more than 7 years of operational data, the technical adjustment will be calculated from averaged historical performance data. Where an existing interconnector has less than 7 years of operational data, the model-based availability will be continuously adjusted using actual availability data.

In line with the majority of respondent views, all outage events occurring within High Demand Settlement Periods (HDSPs) experienced by an interconnector, with no discretionary

[1] DESNZ (2025), Capacity Market: hydrogen and interconnectors – call for evidence
[2] New engineering data as published by CIGRE (the International Council on Large Electric Systems)

exclusions, will be considered in the technical adjustment calculation for interconnectors with one or more years of operational data. A note to provide fuller detail of the final methodology has been published in parallel to this summary of responses.[3]

The government has separately published a response to the consultation on proposed changes to the CM ahead of Prequalification 2026.[4] Stakeholders are encouraged to review the decisions made in this document ahead of Prequalification 2026.

[3] DESNZ (2026), Updated technical adjustment methodology for de-rating interconnectors in the Capacity Market
[4] DESNZ (2026), Capacity Market: proposed changes for Prequalification 2026 government response

2. Introduction

2.1 Background

In December 2024, the government responded to the consultation on the need for a market intervention to enable the deployment of H2P[5] which committed to introduce a new H2P business model (H2PBM). Alongside this, the government also committed to enabling H2P to participate in the CM as soon as practical. The government expects the H2PBM to be the main route to market for H2P plants, but some H2P plants could come forward through the CM initially, with this number rising as the technology develops and deployment barriers fall away. As outlined in the December 2024 consultation response announcing the H2PBM,[6] the government expects the CM to be the enduring support mechanism for H2P deployment in the long term.

The government launched a Call for Evidence on H2P and Interconnectors in October 2025.[7] The Call for Evidence sought stakeholder views on how to categorise H2P to inform potential changes to the CM to enable participation, and on a new approach for determining the technical reliability of interconnectors for the purpose of setting their de-rating factors.

Through this Call for Evidence, the government sought to understand how different types of H2P plants, including blended plants, should be categorised within the CM. The government wanted to test which Generating Technology Classes (GTCs) and associated de-rating factors would be most applicable to the different possible configurations of H2P plants. This document provides an overview of stakeholder views presented on the Call for Evidence topics, including any alternative suggestions. The summary of responses set out in this document should not be considered to reflect any finalised decision on H2PBM design.

Electricity interconnectors connect the transmission systems of two countries, enabling the import and export of electricity. They support security of supply by enabling access to more diverse generation over a wider geographic area. Their two-way capability also provides flexibility by helping the system respond rapidly to changes in supply and demand, and balance periods of higher or lower generation as we integrate more intermittent renewables. This means that, when GB generates more electricity than it needs, a strong interconnector system will allow us to export the excess electricity, thus contributing towards the Clean Energy Superpower Mission.

All technologies which participate in the CM are de-rated to reflect their contribution to security of supply at times of system stress. The CM Rules set out how each technology that may participate in the CM is de-rated.[8] The multi-step process for determining interconnector de-rating factors is set out in Schedule 3A of these Rules.[9] The final step of this process is a

---

[5] DESNZ (2023), Hydrogen to power: market intervention need and design
[6] DESNZ (2024), Hydrogen to power: market intervention consultation: government response
[7] DESNZ (2025), Capacity Market: hydrogen and interconnectors – call for evidence
[8] DESNZ, Capacity Market Rules, Chapter 2.3, accessed March 2026
[9] DESNZ, Capacity Market Rules, Schedule 3A, accessed March 2026

technical adjustment which the government applies to reflect the technical reliability of interconnectors. The government commissioned Frontier Economics and LCP Delta to provide and recommend updated approaches to consider technical reliability which could be applied when determining interconnector de-rating factors.[10]

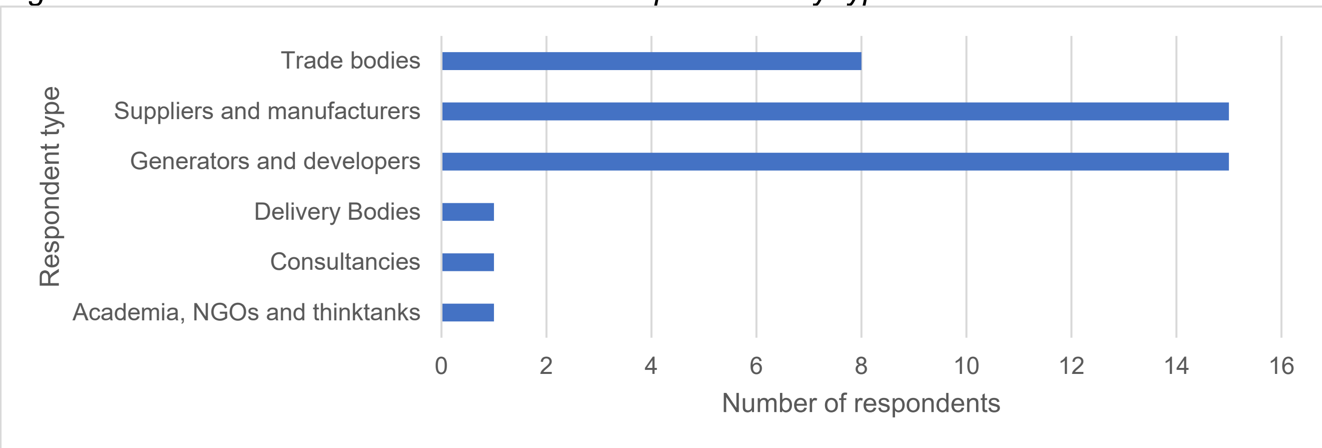
Through this Call for Evidence, the government sought to understand stakeholder appetite toward updating the methodology used to calculate technical adjustments for interconnector de-rating factors, based on the recommendation from Frontier Economics and LCP Delta, for implementation ahead of the 2026 Prequalification window.

In parallel to this summary of responses, Government has published a response to the consultation on proposed changes to the CM ahead of Prequalification 2026.[11] Stakeholders are encouraged to review the decisions made in this document ahead of Prequalification 2026.

2.2 Call for Evidence Responses

The Call for Evidence was published on gov.uk and ran from 2 October 2025 to 27 November 2025. The Call for Evidence received 41 responses from a range of stakeholders, including developers and generators, suppliers and manufacturers, trade bodies, delivery bodies, academia, non-governmental organisations (NGOs), and thinktanks. These responses were submitted through an online portal (Citizen Space, 16 responses) or by email (25 responses). Figure 1 provides a breakdown of respondents by type. The government is grateful to all respondents to the Call for Evidence for taking the time to submit their views.

Figure 1 – Breakdown of Call for Evidence respondents by type.



This document summarises the feedback received to the H2P section of the Call for Evidence. It also summarises the feedback received to the interconnector section of the Call for Evidence and the changes to the interconnector de-rating methodology that have been made, after taking into consideration stakeholder views.

[10] DESNZ (2025), Technical Derating factors for electricity interconnectors
[11] DESNZ (2026), Capacity Market: proposed changes for Prequalification 2026 government response

All responses to the Call for Evidence have been analysed, however due to the commercially sensitive nature of some responses, the response summary to some questions has been abridged.

In summarising the responses received to each question, “the majority” indicates a view was held by more than 50% of respondents to that question, “most” or “many” indicates more than 70%, “some” between 30% and 70%, and “a few” less than 30% of respondents who expressed a view. This is consistent with the approach used for other UK government responses.

3. Participation of Hydrogen to Power

3.1 Summary of Call for Evidence

H2P and its associated enabling hydrogen infrastructure (production, transport and storage) are emerging technologies. In this Call for Evidence, the government sought views on how H2P plants should be categorised within the CM to enable their participation, including whether existing GTCs are appropriate or whether bespoke GTCs and de-rating factors should be developed. The response to this Call for Evidence is a summary of responses received and not a comment on policy change or development.

We welcome the valuable feedback from stakeholders and will undertake further policy development and engage with CM delivery bodies to develop a proposed approach to H2P participating in the CM. We intend to outline our proposals later this year.

The Call for Evidence set out that H2P encompasses a range of configurations with differing technical and commercial characteristics, including:

- combustion plants connected to a wider hydrogen network, with or without a natural gas connection;
- closed loop systems with onsite hydrogen production and/or storage;
- plants blending hydrogen and natural gas onsite; and,
- hydrogen fuel cells, which are electrochemically driven and therefore distinct from combustion technologies

Questions 1 – 6 sought stakeholder views on whether existing GTCs could be applied to early H2P projects, including those with a natural gas connection, those without, and those with on-site storage. Government wanted to test whether H2P plants with access to a natural gas connection, or with onsite storage could, in the near term, be classified under existing gas GTCs or existing storage GTCs respectively, subject to testing the assumption that reliability would be comparable to unabated gas generation and keeping such classification under review as operational evidence emerges. Views were also sought on what would need to be considered for the development of bespoke de-rating factors for H2P plants (both combustion and fuel cell), as well as what wider factors and unintended consequences there could be.

Questions 7–12 focused specifically on onsite blending of hydrogen and natural gas, seeking evidence on whether the existing CM framework is sufficient to accommodate blending, whether blending would materially affect plant reliability or maintenance requirements, and whether new or amended GTCs may be required for blended configurations.

3.2 Applying existing GTCs to early H2P projects

Summary of responses

Question 1 asked respondents for their views on whether Hydrogen to Power (H2P) plants, that were connected to the wider hydrogen network and with natural gas connections, could participate in the Capacity Market (CM) under existing Generating Technology Classes (GTCs). Of the 33 responses received, 27 respondents (82%) agreed that existing gas GTCs were appropriate for H2P combustion plants in this scenario. In total, 5 respondents (15%) disagreed with the statement, and the remaining respondents (3%) were unsure.

Of those that agreed, a few respondents suggested that existing gas GTCs should be used during the transitional period of H2P participation in the CM, but that further operational data may suggest the need for a bespoke GTC. A few respondents also suggested that future consultation with Original Equipment Manufacturers (OEMs) on the performance differentials of hydrogen and gas optimised assets may show the need for a bespoke GTC.

Question 2 asked respondents whether existing gas GTCs and their associated de-rating factors, would be suitable for H2P combustion plants connected to the wider hydrogen network without gas connections. Out of the 28 responses received, 13 respondents (46%) agreed that existing gas GTCs would be sufficient and 15 respondents (54%) disagreed with this statement.

Some of the respondents who disagreed or caveated their support for using a gas GTC showed concern over the nascency of hydrogen infrastructure, and a few responses argued that combustion plants without natural gas connections may be less reliable in the CM.

A few respondents who disagreed with the statement suggested that gas GTCs may be suitable in the long-term, once the hydrogen network matured. Others thought that projects connected to large-scale geological hydrogen stores could use existing gas GTCs with associated de-rating factors, while projects without this connection should use a bespoke GTC.

A few respondents also suggested alternative approaches to CM categorisation for plants connected solely to the hydrogen network. Suggestions included a project specific approach to determining de-rating factors or participation under existing gas GTCs but with a bespoke de-rating factor.

Those respondents who agreed that existing gas GTCs and their associated de-rating factors were suitable noted that GTCs should not be determined based on fuel input and that using existing gas GTCs would reduce administrative complexity in the CM.

Question 3 asked respondents about H2P plants without access to natural gas, but with onsite storage, being categorised as duration limited and classified as Storage Generating Technology. Eighteen respondents broadly supported the proposal, acknowledging that onsite storage inherently constrains duration, thereby aligning such assets with the operational characteristics of storage technologies. Some respondents emphasised that where stored hydrogen determines deliverable capacity, applying storage style de-rating factors is logical, provided they accurately reflect plant specific characteristics such as storage volume, refill rates, electrolyser output, and expected operational patterns.

The majority of respondents favoured the proposed categorisation but caveated with some concerns. Concerns centred around fuel availability, storage sizing, efficiency, and the need for precise calibration of de-rating methodologies. Others supported the classification but emphasised that de-rating should not penalise plants that can demonstrate sufficient onsite storage to meet contractual obligations. Transparency and improved modelling, especially around historical performance, refill time, and response during stress events, were frequently highlighted as necessary improvements to the current framework.

The majority of respondents argued for expansion of the eligible technology scope within the CM. Many pointed to ammonia-to-power and ammonia storage as realistic alternatives that should be explicitly included, given ammonia's easier handling, suitability for large-scale storage, and compatibility with existing infrastructure. These respondents stressed the importance of technology agnostic rules to avoid stifling innovation and ensure promising H2P and ammonia-fuelled solutions can participate effectively.

However, five respondents (16%) raised strong objections to the proposed classification. Respondents argued that categorising these assets as duration-limited fundamentally misrepresents their capabilities. It was noted that such systems can provide weeks of continuous dispatch, far exceeding the endurance of batteries or traditional storage assets. Another objection was that applying storage de-rating factors would severely under-reward these projects, reducing revenue by 40 – 60%, distort market signals, and risk deterring investment in infrastructure that could materially enhance long-term energy security.

Other respondents argued that a bespoke GTC is needed because hydrogen combustion plants differ technically and operationally from both batteries and conventional thermal plant. Applying battery derived de-rating factors is seen as inappropriate for assets designed for seasonal or long duration storage cycles. These respondents recommended a generator type de-rating approach like Open Cycle Gas Turbines (OCGTs), Combined Cycle Gas Turbines (CCGTs), or Combined Heat and Power (CHP), rather than a storage duration approach.

Overall, while there was substantive support for classifying limited-storage H2P as duration limited with storage style de-rating, several respondents advocated for clearer methodologies, hydrogen specific refinements, or entirely separate classifications for long duration or large-scale hydrogen storage systems.

Question 4 asked which factors would need to be considered when developing a de-rating factor for a bespoke GTC for H2P plants without a natural gas connection. Most respondents had broad agreement that if the government introduced bespoke GTCs for H2P plants, for both combustion and fuel cell variants, the development of appropriate de-rating factors must account for the unique characteristics of hydrogen technologies and the surrounding supply infrastructure. Most responses stressed that hydrogen power generation differed materially from natural gas generation and battery storage, requiring tailored, evidence-based approaches.

A key concern from many responses was the centrality of fuel security. Where hydrogen supply was firm, reliable, and diversified, through onsite storage, geological storage, co-located electrolysers, or mature network access, stakeholders noted de-rating factors could be like those of natural gas plants. Equally, where supply depends on early-stage hydrogen networks or intermittent electrolytic production, de-rating must be more conservative. Several respondents emphasised that hydrogen network immaturity, shared infrastructure risks, and correlated network outages may introduce systemic vulnerabilities that differ from individual generator reliability.

The majority of respondents argued that hydrogen combustion plants are technologically comparable to natural gas turbines, both in availability and operational characteristics. It was mentioned that de-rating factors should mirror natural gas classes, and hydrogen specific penalties should be avoided. Some of these respondents also argued that infrastructure risks should not be passed onto operators through lower de-rating factors. Others argued that existing natural gas classes should temporarily accommodate hydrogen combustion units until sufficient real-world data justifies bespoke categories.

Fuel cells received more cautious treatment, with respondents noting their novelty, limited operational history and data, different purity requirements, and distinct failure modes, suggesting bespoke GTCs may therefore be more appropriate for fuel cells than for combustion plants. Respondents advised that factors such as ramp rates, start-up profiles, degradation, and hydrogen purity requirements must be assessed independently from combustion technologies.

Respondents also highlighted technology specific performance considerations. These include thermal efficiency differences, reduced calorific value of hydrogen, performance loss when burning hydrogen versus natural gas, fallback or dual fuel capability, and the ability to maintain output over sustained stress events. Some respondents noted that hydrogen combustion through Internal Combustion Engines (ICEs) may outperform fuel cells in robustness, cost, and power density, and therefore should not share generic hydrogen GTCs.

Some respondents stressed the need to consider storage characteristics, volume, discharge duration, refill rate, and dependency on upstream power availability, particularly for onsite or closed loop systems. These characteristics should influence de-rating but must avoid penalising plants with substantial, reliable storage capable of enduring multi-day stress events.

Operational monitoring was another recurring theme. Some respondents recommended robust frameworks for verifying delivered hydrogen blends, uptime, and supply chain reliability. Respondents also raised weighted moving averages of availability performance, treatment of high-impact low-probability events, and consistent methodologies across combustion, fuel cell, ammonia-to-power, and hybrid units as design imperatives.

Finally, the majority of respondents cautioned against implementing bespoke GTCs prematurely, given limited real world operational data for H2P plants. Evidence from early projects should shape future refinement to avoid inaccurate or overly conservative de-rating that could undermine investment and deployment.

Question 5 asked respondents about wider factors that need to be considered to enable H2P participation in the CM. This question received 28 responses.

The majority of respondents suggested that market incentives were needed to ensure that hydrogen technologies are competitive in the CM. Suggestions included; allowing revenue stacking for hydrogen projects in the CM; introducing targeted price support mechanisms for hydrogen; creating a CM penalty regime that considers the specific challenges of hydrogen usage; and providing long-term CM contract certainty. Additionally, a few respondents specified that new-build H2P plants may require payments above the current CM Price Cap.

A few responses also referenced the wider hydrogen value chain, with respondents highlighting the need for hydrogen supply assurance, a mature hydrogen network, or policy alignment with the H2P Business Model.

A few respondents asked for clarification on emissions reporting arrangements for blended plants and noted the need for robust emissions-accounting frameworks.

Responses also referenced wider factors associated with the CM. A few provided suggestions that Prequalification rules should be clear and feasible for blended projects, CM contracts should provide long-term security, and that system integration challenges should be mitigated. A few respondents highlighted the need for clear technical and regulatory standards or specified that CM rules restricting plant reconfiguration after Prequalification need to be reviewed.

Question 6 asked respondents about unintended consequences that could occur from enabling H2P to participate in the CM. Of the 26 responses, 20 respondents (77%) said there could be unintended consequences and 6 respondents (23%) said there would be no unintended consequences.

Some respondents were concerned with hydrogen infrastructure reliability, and one respondent also highlighted supply chain constraints for gas turbines. A few respondents suggested that H2P plants may be disadvantaged in the CM due to inadequate infrastructure or highlighted concerns over energy security during system-stress events.

A few responses also suggested that H2P participation in the CM could inadvertently increase carbon emissions, either through hydrogen production or diluting investment incentives for fully hydrogen capable equipment.

A few respondents noted the need for clear guidance around the participation and operation of other revenue support schemes, the need for clarity on CM reforms, and the potential for increased administrative complexity.

A few respondents said H2P participation in the CM could result in market distortion or that the implementation of multiple GTCs with different de-rating factors, without a means of corroborating ongoing conformance, created the potential for ‘gaming’ by CM Units.

Government response

The government thanks respondents for this feedback. These responses will inform future thinking and any further policy proposals regarding the participation of H2P in the CM.

We note that a clear majority of respondents supported the governments assumptions that early H2P combustion plants with natural gas connections can be appropriately accommodated within existing gas GTCs.

The government will consider this feedback carefully, refining its approach and assessing whether bespoke GTCs or de-rating factors may be required as operational evidence of H2P participation in the Capacity Market develops and the hydrogen economy matures.

We will undertake further policy development and engage with CM delivery bodies to develop a proposed approach to H2P participating in the CM. We intend to outline our proposals later this year.

3.3 Views on onsite blending of hydrogen and natural gas

Summary of responses

Question 7 asked respondents if operators of existing gas CMUs are considering onsite blending of hydrogen and natural gas for generation and whether the current CM framework is sufficient to enable blending. This question received 22 responses.

In total, 13 respondents (59%) confirmed they have been actively considering onsite blending, often as part of broader decarbonisation plans or feasibility studies. These respondents noted that blending offers a pragmatic pathway toward hydrogen ready operation, reduces carbon intensity, and can be implemented incrementally. The majority of respondents considering onsite blending highlighted technical feasibilities: ICEs can accept low percentage hydrogen blends with minimal modification, while gas turbines from major OEMs are increasingly being designed or upgraded for hydrogen capability.

However, some operators that have been considering blending stated that the current CM framework alone is insufficient to make these investments viable. They cited high capital costs, downtime for retrofitting, limited OEM hydrogen-readiness for large engines, and wide uncertainty over hydrogen availability and cost. Some respondents welcomed recent CM changes, such as lowering the capex threshold for refurbishment contracts, but note that further reform will be needed as actual hydrogen infrastructure and network costs become visible.

Some respondents emphasised that the CM does not currently incentivise blending. Respondents noted that, even with CM support, blending still requires other revenue sources, such as hydrogen production subsidies, carbon cost reductions, or wider market signals, to offset higher fuel costs and plant modifications. Respondents noted the “missing money” problem: the CM Price Cap, even if increased modestly, cannot fully address the investment gap for hydrogen conversion.

Three respondents (14%) have not considered blending, primarily due to economic barriers. These include the high cost of hydrogen relative to natural gas, need for extensive equipment modifications, and technical complexities associated with even modest (up to 2%) hydrogen blending into the National Transmission System. Some respondents argued that under current market conditions, hydrogen blending is simply not competitive.

Six respondents (27%) were unsure when considering this proposal. They argued that clarity is required around how blended fuels will be treated under the proposed Managed Pathways or multiple-price auction structures.

Overall, while there was strong conceptual support for blending as a decarbonisation route, the majority of respondents generally agreed that the current CM framework does not, on its own, provide adequate financial or regulatory support to scale such projects. Respondents advised that blending would require clarification of the CM Rules, targeted reforms, and importantly, credible hydrogen supply chains before it can be pursued at scale.

Question 8 asked respondents whether the opportunity to blend hydrogen would incentivise them to bring forward new capacity or invest in the lifetime extension of existing unabated gas capacity. Of the 18 responses received, 14 respondents (78%) said they would be incentivised, 3 respondents (17%) were unsure, and one respondent (5%) said that blending would not incentivise them to invest in either.

Of those who agreed that blending hydrogen would be an incentive, the main reasons were that blending is cost-effective and reduces financial risks compared to retrofit to 100% capability, offers a credible transitional decarbonisation pathway and enhances security of supply.

Some respondents who agreed also said enabling factors needed to be in place to incentivise investment. The main enabling factors noted were a greater level of certainty around revenue streams and CM classifications, hydrogen availability and infrastructure readiness, and greater policy certainty.

A few respondents noted that they would be incentivised to invest in life extension projects but would not be incentivised to invest in new build projects.

Question 9 asked respondents whether existing GTCs were sufficient for hydrogen and natural gas blended fuel plants. Out of the 25 responses received, 20 respondents (80%) agreed that existing GTCs were suitable and 5 respondents (20%) disagreed.

Responses that agreed with the statement explained that using existing GTCs would reduce administrative complexity in the CM, enable rapid deployment of hydrogen technologies and provide market clarity. A few respondents also suggested that the capacity market should maintain categorisation based on combustion technology rather than fuel input.

Of the respondents who agreed, a further few specified that existing GTCs would be suitable for lower blend ratios. A few respondents also suggested using gas GTCs in the near-term and revisiting the need for a bespoke GTC once empirical operational data becomes available.

Of the respondents who did not support using existing GTCs, the key themes highlighted were the nascency of hydrogen infrastructure, the novelty of H2P technology, and potential issues with meeting CM obligations.

Question 10 asked respondents about unintended consequences that could occur from enabling natural gas plants to blend hydrogen in their fuel mix. This question had 23 responses and 12 respondents (52%) suggested there could be unintended consequences from enabling natural gas plants to blend hydrogen. Eleven respondents (48%) said there would not be unintended consequences.

Of the respondents who suggested there could be unintended consequences, a few argued there were technical risks with blending hydrogen, noting the different combustion properties of natural gas and hydrogen, the potential for pipeline decay due to embrittlement and manufacturing limitations.

A few respondents said there was a risk that hydrogen blending could negatively impact the decarbonisation benefits of hydrogen, with a further few specifying that this could reduce investment incentives for low-carbon technology. Some respondents said that hydrogen availability and a lack of hydrogen infrastructure was a risk, and a few respondents noted that blending could crowd out other offtakers.

A few respondents highlighted the need for clear and consistent GTCs and de-rating factors in the CM, and another few asked for consistent reporting and classification frameworks.

Question 11 asked respondents about wider factors needed to enable hydrogen and natural gas blending in the CM. This question received 19 responses.

A majority of respondents agreed that sufficient market incentives and policy guidance are needed to enable blending in the CM. Some respondents suggested that they require clear investment signals, and a few responses suggested that blended plants may need higher CM payments. Additionally, some respondents wanted clear policy signals for blended plants in the CM. Suggestions included clarity over how blended projects will be treated in the CM, and alignment with the 2025 October CM consultation, including guidance over whether projects can access a proposed higher Price Cap.

Some respondents also suggested that hydrogen infrastructure readiness was needed to enable blending in the CM, with a few further highlighting the need for hydrogen supply chain resilience.

Some responses noted that blended plants would need updated emissions-reporting requirements and clear regulatory standards for blended fuel composition. A few responses also suggested that operating procedures or safety cases would have to be revised to reflect the characteristics of hydrogen combustion. Additionally, a few responses said that definitions of primary fuel type should be reviewed and that further clarification was needed over rules around fuel switching. A few respondents asked for clear guidance on planning and regulations in the CM.

Question 12 asked respondents whether plants would require more frequent maintenance or generation outages or incur higher maintenance costs to enable blending of hydrogen and natural gas. Of the 18 responses received, 11 respondents (61%) suggested that overall, they did not anticipate a significant increase in maintenance or generation outages, or higher maintenance costs. Seven respondents (39%) suggested that additional maintenance would be required.

Of the 11 respondents who disagreed, some suggested that there would be no additional maintenance outages or associated costs compared to gas assets. A few respondents suggested that while some additional maintenance may be required in the early years of the hydrogen economy, as technology matures this need would reduce to match conventional gas assets.

Of those who suggested that additional maintenance would be required, the key themes highlighted were the effects of hydrogen combustion on existing equipment, emissions management and monitoring raising costs, the need for control system adjustments and the need for additional safety management.

A few respondents who suggested that additional maintenance would be required also suggested that there would be a more notable increase in the frequency and cost of maintenance in the early years of hydrogen technology. A few of these responses differentiated by blend ratios, suggesting that higher blends would require more frequent maintenance.

Government response

The government thanks respondents for this feedback. These responses will inform future thinking and any further policy proposals regarding the blending of hydrogen and natural gas in the CM.

We note that respondents broadly agreed that hydrogen-and-natural-gas blended plants can continue to participate under existing gas GTCs in the near term.

We will undertake further policy development and engage with CM delivery bodies to develop a proposed approach to H2P participating in the CM. We intend to outline our proposals later this year.

4. Technical adjustment of interconnector de-rating factors in the CM

4.1 Call for Evidence position

As the calculation to determine the technical reliability of interconnectors had not been reviewed since it was first implemented in 2015,[12] the government commissioned Frontier Economics and LCP Delta to provide updated approaches to consider technical reliability which could be applied when determining final interconnector de-rating factors. This section of the Call for Evidence was designed to seek views on the technical adjustment used for setting interconnector de-rating factors in the CM.

In their report, Frontier Economics and LCP Delta proposed a methodology based on the length of time that each interconnector has been operational, and therefore the amount of historic availability data available to assess technical availability:[13]

- An interconnector with less than 1 year of operation would have its technical availability defined as the minimum of the availability range derived using the most recent SKM model, updated with any new engineering data,[14] or where there is little historic availability data, the technical characteristics of that interconnector.
- An interconnector with between 1 and 7 years of operation would have the model-based availability adjusted annually using a moving average, in line with its observed availability during periods of high demand in winter, to take into account updated historical availability data.
- An interconnector with 7 or more years of operation would have its technical availability derived through its average availability during periods of high demand over the last 7 winters.

Questions 13 – 15 of the Call for Evidence sought views on whether the current technical adjustment methodology should be updated and whether the methodology recommended by Frontier Economics and LCP Delta should be implemented in its place. The government's minded-to position in the Call for Evidence was to implement the recommended approach as it preserved predictability and transparency as an interconnector accumulates evidence of its availability over the years.

As part of this recommended approach, Frontier Economics and LCP Delta proposed options on whether to include all outage events or exclude high-impact low-probability events from the availability assessment. Therefore, questions 16 – 18 of the Call for Evidence sought views on whether high-impact low-probability events should be accounted for or excluded within the

[12] DECC (2015), Consultation on Capacity Market Supplementary Design Proposals and Transitional Arrangements,
[13] DESNZ (2025), Technical Derating factors for electricity interconnectors
[14] New engineering data as published by CIGRE (the International Council on Large Electric Systems)

technical adjustment calculation. Government's minded-to position in the Call for Evidence was to implement Frontier Economics and LCP Delta's recommendation in full and generally exclude certain high-impact low-probability events from the technical adjustment calculation.

Question 19 of the Call for Evidence sought views on whether the government should publish a briefing note to explain the methodology behind the technical adjustment for stakeholders, reflecting previous practice of providing stakeholders with information on interconnector de-rating factors through published briefing notes.

Question 20 of the Call for Evidence sought wider stakeholder feedback on the broader interconnector de-rating process.

4.2 The technical adjustment methodology for interconnector de-rating factors

Summary of responses

Question 13 sought views on whether the government should implement an updated technical adjustment methodology. Of the 16 responses received, 15 (94%) were supportive of updating the technical adjustment methodology, with the remaining response not relevant to the question. Some respondents who were supportive of the government's proposed position emphasised the need for greater transparency to the technical adjustment process.

Most respondents agreed that the government should implement an updated technical adjustment methodology, and many offered additional commentary to bolster their response. Some of these respondents noted that the current methodology has not been updated since its introduction and suggested that a new methodology would improve the accuracy of the technical adjustment calculation.

Question 14 invited views on whether the government should implement the proposed methodology based on the length of time that each interconnector has been operational as detailed above. Of the 14 responses received, 12 respondents (86%) supported the government implementing the proposed methodology for the technical adjustment calculation, one respondent (7%) supported government updating the technical adjustment calculation but opposed the implementation of the proposed methodology, and the remaining response (7%) was not relevant to the question.

The majority of respondents supported this proposal. These respondents highlighted several positive themes, including that the methodology was sensible, clearly defined, and could be consistently applied across the interconnector fleet.

A few respondents raised concerns about how major refurbishment for interconnectors would be defined in the proposed methodology and stressed that government should clearly set the refurbishment criteria before implementing any new methodology. Some respondents asked the government to consider further changes to the methodology, including, where available, using more than 7 years of operational data in the calculation to expand the dataset, and applying a different weighting between operational data and the model-based availability, with a greater weighting toward the former. One respondent proposed an alternative methodology which would use data from the full delivery year, rather than only peak periods, to calculate the technical adjustment.

Question 15 asked stakeholders if there were any unintended consequences to implementing the proposed methodology. Of the 12 responses received, 9 respondents (75%) provided unintended consequences for the government to consider, and 2 respondents (17%) reported no unintended consequences to the proposed methodology. The remaining response (8%) was not relevant to the question.

Some respondents identified unintended consequences to the implementation of the proposed methodology, noting a risk that it could over-penalise new interconnectors with limited operational datasets by assigning disproportionately low de-rating factors. One of these respondents added that refurbishing interconnectors could also be over-penalised if treated as new assets, which could discourage interconnectors undergoing refurbishment if this resulted in a lower de-rating factor.

Other respondents suggested that short periods of poor performance could have undue impact on the technical de-rating factor. One respondent felt that historic availability would not be reflective of future availability and therefore should not be used in the technical adjustment calculation. Other respondents noted that any change to interconnector de-rating factors could affect CM auction liquidity. Finally, one respondent noted that an interconnector awarded a T-4 CM agreement would have its technical adjustment based on data from up to 11 years prior at the year of delivery and questioned if this approach was appropriate.

Government response

Given the strong support, the government will update the technical adjustment methodology. Most respondents to the Call for Evidence indicated support for the implementation of the proposed methodology for the technical adjustment based on the length of time that each interconnector has been operational. Therefore, the government will implement this methodology for calculating interconnector de-rating factors ahead of Prequalification 2026.

In response to feedback, the government considers that the proposed methodology using both theoretical and operational data strikes a balance between capturing robust theoretical engineering-based assessments (from SKM reports) while aligning more closely with wider methodologies that account for historic operation. The government also believes that aligning the timelines for historic operational data with the approach taken for conventional technologies, focusing on winter peak demand periods for the last 7 years as recommended in the report by LCP Delta and Frontier Economics, remains appropriate. Whilst the datasets available to calculate interconnector de-rating factors are smaller than for other technologies, older data or periods outside of winter peaks may not appropriately reflect current operational reliability in line with CM delivery expectations.

4.3 Consideration of high-impact low-probability events in the technical adjustment methodology for interconnector de-rating factors

Summary of responses

Question 16 sought views on whether the government should generally exclude high-impact low-probability events from the technical adjustment calculation. Of the 18 responses received, 10 respondents (56%) opposed the government's minded-to position of including all high-impact low-probability events in the technical adjustment calculation, 6 respondents (33%) supported excluding certain high-impact low-probabilities from the calculation, and 2 respondents (11%) provided commentary but did not explicitly favour one decision over the other.

In the Call for Evidence, the government proposed generally excluding high-impact low-probability events from the technical adjustment calculation. Some respondents supported this view. These respondents argued that these events should be excluded as by definition, they are low-probability and because past events do not predict future events. Other respondents supported this view because they considered that excluding high-impact low-probability events would improve predictability for market.

The majority of respondents disagreed with the proposal to exclude events and instead supported the view that the technical derating calculation should consider all operational data. Some of these respondents argued that high-impact low-probability events should be included as all outage events are used to de-rate other technologies, therefore excluding certain high-impact low-probability events would create inconsistency with broader approaches. Other respondents noted that the high-impact low-probability events described in the report by Frontier Economics and LCP Delta occur frequently and suggested these should not be excluded from the calculation. Finally, a few respondents argued that excluding high-impact low-probability events would underestimate the risks associated with relying on interconnectors for security of supply, and that predictable interconnector de-rating factors did not outweigh the potential risk to electricity security of supply.

Question 17 asked stakeholders to provide views on which criteria, if any, should lead a high-impact low-probability event to be excluded in the technical adjustment calculation. Of the 12 responses received, 4 respondents (33%) reaffirmed their position that no outages should be excluded from the calculation, 7 respondents (58%) provided criteria for high-impact low-probability events that should be considered by government as excludable events in the technical adjustment calculation, with the remaining response (8%) not relevant to the question.

Respondents who supported the view that certain high-impact low-probability events should be excluded from the technical adjustment calculation believed that Transmission System Operator (TSO)-instructed capacity reductions, events outside of the control of the interconnector, and force majeure events such as fires and natural disasters should be categorised as high-impact low-probability events that should be excluded from the calculation.

A few respondents also suggested that assets should provide confidential information to government on the cause of a high-impact low-probability outage where relevant to the technical adjustment calculation, and that government should consider whether interconnector assets had taken remedial action following a high-impact low-probability event when calculating interconnector de-rating factors.

Question 18 asked stakeholders if there were any unintended consequences to excluding high-impact low-probability events. Of the 12 responses received, 11 provided responses relevant to the question, and one response (8%) was not relevant to the question. Two respondents (17%) stated they did not think there were unintended consequences from excluding high-impact low-probability events from the calculation. One respondent instead believed that including high-impact low-probability events in the technical adjustment calculation would result in unintended consequences.

The remaining 9 respondents (75%) believed that excluding high-impact low-probability events would create unintended consequences. These respondents outlined issues including potentially underestimating system risk, for example given the potential increased occurrence of high-impact low-probability events due to climate change. Respondents also noted the risk of inconsistency with the approach taken to de-rate other technologies, as well as the risk of disputes if high-impact low-probability criteria were incorrectly defined and applied in the technical derating process.

Some respondents suggested mitigations to these unintended consequences that the government could consider in further policy scoping, if the government made the decision to exclude them. These included regular reviews of the criteria for excluding high-impact low-probability events and placing a cap on the number of exclusions that could be applied to the technical adjustment calculation.

Government response

The government welcomes the feedback and commentary from respondents. In light of this feedback, the government has decided to include all high-impact low-probability events in the technical adjustment calculation. This will align the methodology for interconnectors more closely with the de-rating approach used for other technologies and removes ambiguity regarding why certain events are excluded while others are not.

This decision ensures the methodology reflects the full range of risks relevant to security of supply and maintains a clear, transparent rationale for how availability is assessed. The government recognises that this approach could lead to greater volatility in interconnector de-rating factors year-on-year, and could result in potentially different de-rating factors for interconnectors connecting to the same country, even where their theoretical technical performance is reported to be similar.

Excluding certain high-impact low-probability events could result in less volatile de-rating factors determined year-on-year and allow the technical adjustment to more closely reflect expected availability in scenarios where truly one-of-a-kind events have occurred. However, this option creates inconsistencies with the treatment applied to other technologies and risks introducing ambiguity regarding which events merit exclusion. By discounting these events, this approach may also understate genuine risks, leading to de-rating factors that do not fully reflect potential interconnection availability during System Stress Events.

Following an in-depth appraisal of both options, the government will include all high-impact low-probability events in the technical adjustment calculation in line with the majority view of respondents. The government has taken this decision as it has fewer associated risks to security of electricity supply and because the difference between including all outage events and excluding certain events has a comparably minor impact on the overall determined interconnector de-rating factor compared to other stages of the de-rating process.

4.4 Publication of a note to detail the methodology behind the technical adjustment

Summary of responses

Question 19 sought views on whether the government should publish a briefing note to detail the methodology behind the technical adjustment. Of the 17 responses received, 16 respondents (94%) were in favour of the government publishing a briefing note to detail the technical adjustment methodology, with the remaining response (6%) not relevant to the question.

The majority of respondents supported the government publishing a briefing note. Most respondents agreed that this would improve transparency and accountability by helping participants better understand the interconnector de-rating process. Some respondents suggested that this publication would benefit industry, improving investor confidence and aiding future constructive engagement between industry and the government on de-rating interconnectors.

Some respondents asked for additional aspects to be included in the note, such as worked examples to help industry understand how technical adjustments are calculated and transparency on the data sources the government will use to calculate the technical adjustment. A few respondents requested the notes to be published annually to reflect the evolution of interconnector performance over time.

Government response

In line with the supportive responses, the government has published a note to detail the methodology alongside this Call for Evidence, which includes worked examples and transparency on the data sources used, reflecting stakeholder requests. The government considers that updates to the note will only be necessary if the methodology undergoes further updates in approach or adjustments.

4.5 Further views on the wider interconnector de-rating factor process

Summary of responses

Question 20 invited further comments on the wider interconnector de-rating factor process. This question did not have an associated proposal and was intended as an opportunity for stakeholders to share broader feedback where not captured by the Call for Evidence on technical derating methodologies. Of the 12 responses received, 7 respondents (58%) provided a direct response, while 5 respondents (42%) offered indirect commentary as part of their wider response to the Call for Evidence.

Some respondents indicated support towards NESO's approach regarding an incremental Equivalent Firm Capacity (EFC) methodology to calculate interconnector de-rating factors as detailed in their 2025 Electricity Capacity Report,[15] and noted this is consistent with the approach taken for de-rating variable technologies for the CM. Other respondents requested additional scrutiny of the EFC methodology before NESO implemented it in full. A respondent also emphasised that DESNZ must coordinate with NESO ahead of any implementation.

Several respondents commented on the wider interconnector modelling process. One respondent suggested that the interconnector modelling process must reflect interconnector-specific operational and geopolitical risk profiles, as interconnectors face different risks. Another respondent suggested that conservative modelling assumptions would indirectly lead to higher consumer bills. One respondent called for a full review of the interconnector de-rating process.

One respondent asked the government to revisit cross-border participation in the CM, noting that interconnector's current participation in the CM was originally intended as an interim method until cross-border arrangements were implemented. Another respondent suggested that cross-border policy might undermine interconnector availability if implemented in the future. Another respondent questioned whether interconnectors should continue to participate in the CM and urged the government to review this.

[15] NESO (2025), Electricity Capacity Report 2025

Some respondents urged the government to promote the use of hydrogen interconnectors (similar to current gas pipelines) and noted that the introduction of H2P in the CM might reduce reliance on electricity interconnection.

Government response

The government thanks respondents for this feedback. These responses may inform future thinking and any further policy proposals regarding how interconnectors are de-rated in the CM.

5. Conclusions and next steps

The government would like to thank respondents for taking the time to answer these questions and for providing both evidence and suggestions on H2P and interconnectors in the CM. The government remains committed to engaging and working with industry stakeholders as an integral part of the policy development process.

Responses to questions 1 – 12 of the Call for Evidence will continue to be considered and reviewed by the government as part of H2P policy development.

After taking into consideration the responses to questions 13 – 20 of the Call for Evidence, the government has decided to make the following changes to the interconnector de-rating methodology:

- **Update the technical adjustment process to use the proposed calculation for the interconnector de-rating factors set from Prequalification 2026 onwards:** The Call for Evidence was met with strong support for updating the technical adjustment methodology to the methodology recommended by Frontier Economics and LCP Delta when setting future interconnector de-rating factors. For new and refurbishing interconnectors, the technical adjustment will be defined as the minimum of the availability range derived using the most recent SKM model, updated with any new engineering data, or where there is little historic availability data, the technical characteristics of that interconnector. For existing interconnectors with more than 7 years of operational data, the technical adjustment will be calculated from averaged historical performance data. Where an existing interconnector has less than 7 years of operational data, the model-based availability will be continuously adjusted using actual availability data.
- **Include all high-impact low-probability events in the technical adjustment calculation:** Call for Evidence responses were mixed. Whilst the recommendation by Frontier Economics and LCP Delta was to make discretionary exclusions for certain high-impact low-probability events in the technical adjustment calculation, in line with the majority of respondent views, all outage events occurring within HDSPs experienced by an interconnector, with no exclusions, will be considered for interconnectors with one or more years of operational data.
- **Publish a briefing note:** The government received strong support to prepare a briefing note in line with the wider consultation and Call for Evidence responses. In response to stakeholder feedback, this note has been prepared to increase transparency over the process and to provide a worked example of how the technical adjustments are calculated. Stakeholders are encouraged to review this note for further details on the technical adjustment calculation.

6. List of respondents to the Call for Evidence

The Call for Evidence received 41 responses in total from a range of stakeholders.

Only organisations that gave permission for their Call for Evidence response to be made public have been included on the list below. Responses from individuals or organisations that indicated they do not want identifying information published or did not specify permission to share information have been considered as part of the Call for Evidence responses but are not listed below.

Respondent Name
Ahmed F Zobaa, Brunel University of London
Cadent Gas
Hygenox Holdings Limited
Rolls-Royce Solutions
Rolls-Royce plc
Siemens Energy

7. Glossary

Abbreviation/Term	**Definition**
Capacity Agreement	The rights and obligations accruing to a Capacity Provider under the CM Regulations and the Rules in relation to a CMU for one or more delivery years.
Capacity Auction	An auction held under Part 4 of the Regulations, as a result of which successful bidders are awarded Capacity Agreements.
Capacity Market (CM)	A mechanism to contract reliable sources of capacity, and ensure they respond when needed, to help support security of supply. This results in payment to any Capacity Provider who can respond when called on by the CM Delivery Body in times of system stress. Auctions for this capacity take place both four years (T-4) and one year (T-1) ahead of delivery, and agreements generally last for one year.
Capacity Market Rules (“the CM Rules” or “the Rules)	The CM Rules provide the technical detail for implementing the operating framework set out in the Regulations.
Capacity Market Unit (CMU)	A unit of electricity generation capacity or DSR capacity that can be put forward in a capacity auction. It is the product that forms the capacity to be purchased through the CM.
Capacity Provider	A person who holds a Capacity Agreement or a transferred part in respect of a Capacity Agreement.
Capital Expenditure (CAPEX)	Money spent by a business or organisation on acquiring or maintaining fixed assets, such as land, buildings, and equipment.

CM Delivery Body	National Energy System Operator (NESO).
Combined-Cycle Gas Turbine (CCGT)	(i) An electricity generation technology in which a gas turbine and a steam turbine are used in combination to achieve greater efficiency. (ii) A GTC in Schedule 3 of the CM Rules
Combined Heat and Power (CHP)	(i) An electricity generation technology which captures and utilises the waste heat produced by the electricity generation process (ii) A GTC in Schedule 3 of the CM Rules
De-rated Capacity	The capacity that a CMU is likely to be technically available to provide at times of peak demand, which is specific to the CMU's technology type and individual characteristics.
De-rating Factor	De-rating factors are applied to all forms of electricity generation in the CM to reflect that 100% of capacity will not be available 100% of the time. This is because generating plants can break down from time to time, and wind and solar outputs varies day to day.
Dispatchable Power Agreement (DPA)	A private law contract between a carbon emitting electricity generator and the DPA Counterparty, which will be the Low Carbon Contracts Company Ltd, issued pursuant to Section 10 of the Energy Act 2013, as a type of CfD. The contract will set out the terms for capturing and storing carbon and the compensation which the generator will receive in return.
Electricity Capacity Regulations ("the CM Regulations" or "the Regulations")	This refers to the Electricity Capacity Regulations 2014, S.I. 2014/2043, the principal regulations underpinning the CM.

Flexibility	The ability to shift the consumption or generation of energy in time or location. Flexibility is critical for balancing supply and demand, integrating renewables, and maintaining the stability of the system. Flexibility technologies include power CCUS, H2P, LDES, flexible demand and interconnectors.
Generating Technology Classes (GTC)	A class of Generating Unit, defined by the technology used to generate electricity, for which the Secretary of State requires the CM Delivery Body to publish a De-Rating Factor.
Generator	(i) Any equipment that produces electricity, including equipment which produces electricity from storage; and (ii) A business which operates such equipment.
Gigawatt (GW)	A unit of capacity (1000 megawatts).
Hydrogen to power (H2P)	The conversion of low carbon hydrogen to produce low carbon electricity.
National Energy System Operator (NESO)	An independent, public corporation responsible for planning Britain's electricity, gas and hydrogen networks, as well as operating the electricity system. In the GB electricity system, NESO performs several important functions, from second-by-second balancing of electricity supply and demand, to developing markets and advising on network investments. NESO replaced the National Grid Electricity System Operator on 1 October 2024.
Open Cycle Gas Turbines (OCGT)	(i) An electricity generation technology using a gas turbine without exhaust gas heat recovery. ((ii) A GTC in Schedule 3 of the CM Rules

Panel of Technical Experts (PTE)	An advisory group of independent consultants who were appointed by the government to perform a specific and technical function as part of the first Electricity Market Reform delivery plan process.
Unabated (gas) generation	Electricity generation where carbon dioxide from burning natural gas is not captured and stored.
Reciprocating engine	(i) An electricity generating technology using a reciprocating pistons driving a rotating shaft. (ii) A GTC in Schedule 3 of the CM Rules.
System Stress Event	A System Stress Event occurs only when i) a demand control event has occurred and ii) that demand control event has been confirmed after post-event analysis, conducted by NESO, to have been definitively triggered by a national shortage of generation resources.

This publication is available from: https://www.gov.uk/government/calls-for-evidence/capacity-market-hydrogen-and-interconnectors