Enabling Renewable and Interconnector participation in GB ancillary services

NESO
National Energy System Operator

Contents

1. Executive Summary

The Enabling Renewable and Interconnector participation in GB ancillary services report aims to understand and address challenges to participation in GB ancillary services markets for renewable technologies and interconnectors to ensure that the markets are fit for purpose to meet the needs of a net zero electricity system. The purpose of this report is to identify factors that may hinder participation and provide a view on the future outlook for addressing the challenges, both through National Energy System Operator (NESO) action and in the wider energy landscape. The in-scope markets are primarily the dynamic frequency response services (dynamic moderation, dynamic regulation, dynamic containment) and both existing (STOR, Fast Reserve and Balancing Reserve) and future (Quick and Slow Reserve) reserve markets. Additionally, it is to inform and influence the current and future requirements in terms of technical, commercial, regulatory, and ancillary service design aspects to enable full participation of all technologies that are able to meet the requirements of the service.

As the GB energy market evolves, we need to facilitate the maximum amount of participation possible in order to continue to ensure reliable, cost-effective service provision. As part of our work to identify challenges, we have engaged with solar and wind asset manufacturers, owners and operators, as well as with Irish and mainland European interconnector operators.

Initial findings suggest that the key challenge for wind and solar providers participating in ancillary services markets lie in the current incentive regime that these assets operate under. Under these incentive schemes, the generators must maximise generation output in order to receive subsidies. In the case of the Contracts for Difference (CfD) scheme, the subsidies are a product of the output volume (MWh) and difference between the reference price and CfD strike price, which incentivises these generators to maximise their output. Response and reserve provision would require turning down output or holding back headroom and making a choice between the energy and service markets (as both cannot be provided at the same time). CfD-supported generators will choose the energy market unless the value of the service market exceeds that of the strike price. Providers also noted challenges with day-ahead capacity nominations, baselining, asset testing and power purchase agreements.

One opportunity for addressing the economic incentive challenge, the Review of Electricity Market Arrangements (REMA), may bring about reforms to the current CfD and incentive schemes. REMA is a government programme to identify reforms needed to transition to a decarbonised, cost effective and secure electricity system by 2035. Additionally, closer to real-time procurement and baselining changes are being investigated by the NESO that are expected to broaden access enabling more technology types and providers to participate in ancillary services markets.

There are a number of challenges to interconnector operator participation in GB ancillary services, principally relating to the trilateral arrangements between interconnectors and the interconnected Transmission System Operators (TSOs).

The leading mechanism for the payment of the energy associated with the participation of an interconnector as an ancillary services provider in GB markets does not generally provide an incentive for that participation. This mechanism relies on a TSO to TSO trade to pay for the energy taken from a system connected to GB. This value, stipulated in the BASA (Balancing Services Agreement) agreed between the 3 parties, is not generally commercially viable due to the high energy price specified.

There is a further related challenge for Interconnector participation in that any action on one side of the interconnector has an equal and opposite impact on the other side. This could be destabilising and unpredictable, causing issues for interconnected TSOs. The TSOs either side of the interconnectors would require mutually agreed arrangements to govern how interconnectors would act to stop these activities having detrimental impacts when responding to system events. It is expected that the UK-EU Inter-synchronous Area Group (ISA) harmonisation group will address this topic in due course.

Additionally, GB Response and Reserve auctions are held at the day ahead stage. The TCA (Trade and Cooperation agreement) specifies that the maximum level of capacity on interconnectors should be made available to the wholesale energy market. This makes it potentially challenging for interconnectors to justify bidding capacity into ancillary service markets at the day ahead timeframe, before traders have had the chance to participate in intraday capacity auctions. NESO is investigating closer to real time procurement to reduce uncertainty in this commercial decision.

Each of the identified challenges to participation and an assessment on the future outlook for addressing them is outlined in the following report. A summary table for quick reference may also be found in Appendix 1.

Please note that demand side flexibility is not covered in this report by NESO's work on Flexibility Markets Strategy which can be accessed here.

2. Challenges for Renewable Assets

2.1. Introduction to Renewable Assets

GB has 44GW of wind and solar generation connected presently, with a minimum of 94GW expected to be connected to the network by 2030[1]. Wind generators presently make up 6% of the total energy supply, but this is expected to rise to 41% by 2050. Much of this growth is fuelled by offshore wind[2].

The revenue model for many renewable assets involves securing a guarantee of funding with which they can secure a loan to build an asset. CfDs or PPAs (Power Purchase Agreements) tend to be the primary ways that this is achieved. PPAs are medium to long term contracts that guarantee a price for the energy that a renewable generator is selling. CfDs similarly offer a guaranteed 'strike price' for energy that is generated in the wholesale market, which tends to be above market prices and has mechanisms to ensure that price fluctuations do not impact their revenues and ability to pay back the loan.

Currently, wind and solar generators do not participate in NESO ancillary service markets beyond mandatory services. Neither PPAs nor CfDs are presently designed to be compatible with them.

Challenges for wind and solar participation in ancillary service markets may be considered in a hierarchy. Addressing some challenges that change the ability to participate in smaller ways, such as closer to real time procurement, only make a difference to the entry of renewables into the market when more fundamental challenges like economic incentives are first addressed.

[1] Current renewables generation figures and future estimates are taken from our Future Energy Scenarios Pathways to Net Zero 2024 release, which can be found here; download (nationalgrideso.com)
[2] Current renewables generation figures and future estimates are taken from our Future Energy Scenarios Pathways to Net Zero 2024 release, which can be found here; download (nationalgrideso.com)

2.2. Commercial Barriers and Future Outlook

2.2.1. Economic Incentives

The single biggest challenge identified through engagement with various wind and solar providers was the lack of incentive to participate in ancillary service provision due to existing subsidy schemes that support medium-to-large assets and projects. The most notable of these revenue assurance schemes are Contracts for Differences (CfDs) and Renewables Obligation Certificates (ROCs). Smaller assets built before 2019 were supported by the Feed in Tarif (FiT), and then the Smart Export Guarantee. REGOs (Renewable Energy Guarantees of Origin) are another revenue stream that is available to renewable generators, which provide suppliers, and eventually consumers, with assurance that energy was produced by renewable sources.

These subsidy schemes were initially introduced to incentivise investment in renewable energy projects in Great Britain (GB) to unlock huge capacities of renewable generation, particularly solar and wind. The current CfD scheme guarantees participants a pre-determined ‘strike-price' for every MWh generated. If the Intermittent Market Reference Price (IMRP), based on the day ahead wholesale electricity price, is below the CfD’s strike price, the generator receives a top-up to that level. Conversely, if the IMRP is above the strike price, the generator must pay back into the scheme. They are incentivised to maximise the generation output at all times. The magnitude and long-term nature of these subsidies distorts market behaviours in electricity markets, encouraging generators to maximize generation output to the exclusion of participation in other markets.

This mechanism comes into conflict with ancillary service provision. If a wind or solar generator bids to provide negative response or reserve, it begins operating at its maximum generation level. If the generator was then activated by an ancillary service, it would have to turn down operation to a level of generation lower than the maximum potential output for the activated period. Here, they are losing subsidy revenues equal to the capacity that they have turned down and offered in their ancillary service contract.

In the case of positive response, the renewable generator would need to begin operating for the contracted service length at a lower level of generation than the maximum potential output, losing subsidy revenues unless the control room activates them back to their maximum output. In either case, at current market prices the foregone subsidies are not fully compensated for by ancillary service generation. Hence, owing to the output-based nature of how these incentive schemes work, providing ancillary services incurs opportunity cost associated with foregone subsidy revenue and there remains little to no incentive for generators to provide ancillary services to NESO. Generators receiving support under these schemes therefore make the rational decision not to participate, as service provision would normally require reductions in MWh generation. REGOs have a similar effect to CfDs on the incentives to operate in ancillary service markets (though of a much smaller magnitude), further increasing the financial loss from switching to ancillary services.

A further challenge concerns how competitive renewable assets will be able to be against other asset types. It is anticipated that renewable assets prefer to be operating at maximum generation where possible, given that there is no marginal cost to their generation as with other fuel types, so the most obvious space for their participation in ancillary services is downward response. It may be challenging for renewable assets to compete with battery assets that may see additional advantages from being paid to charge. It was suggested that maintenance costs for renewables may also be higher than for some other asset types. Competitive challenges, particularly in provision of downward, may remain even if subsidy-related incentives are removed.

2.2.2. Economic Incentives Outlook

As part of the Government's Review of Electricity Market Arrangements (REMA) consultations, reforms to the current CfD scheme are being considered. As of the second REMA consultation in March 2024, there are currently four identified reform options. The final decision on a preferred CfD option is waiting on the resolution of other outstanding REMA questions, due to the interaction of these changes with other elements of the reform, with the final decision being made on all of these changes holistically. The modelling of these options by DESNZ is ongoing. The earliest a CfD reform is expected to be implemented is 2028.

If progressed, one objective of the reforms would be to align generators' incentives to market signals, including those for ancillary services. Of the four proposed reforms, there are currently two leading standalone options, the deeming and capacity based CfD. The partial CfD and reference price reform are being looked at as possible augmentations to the chosen leading reform option.

Deeming CfD payments would work through a methodology that tries to estimate the theoretical maximum generation an asset could be producing at a given time unimpeded by ancillary service actions. This methodology would allow for current weather conditions and other real time variables when awarding the subsidy.

The intended result of this reform is that the actual generation of the asset is no longer tied to their CfD, as it is now. Generators can then explore different market strategies, such as ancillary service provision, without the negative impact it will have on their subsidy revenues. Here, the top-up subsidies awarded to wind and solar generators are the product of the difference between the reference price and the strike price and the "deemed", or potential, output. This would potentially free the asset owner to pursue revenues in other markets if this maximizes producer welfare, since the generator could receive the market revenues plus the top-up payment from the subsidy. The generator would no longer have to price the opportunity cost of foregone subsidies if it holds headroom to provide upward response or provide downward response.

The capacity CfD works similarly to the deeming CfD, and could also include an availability factor. Assets would be given a fixed, regular payment based upon installed capacity regardless of actual generation output. Again, assets no longer reduce their subsidy revenues from acting as part of ancillary service markets. The capacity and deeming CfD may be altered to include only a portion of total CfD revenues, as part of the partial CfD option. In that case reform of the IMRP could be a hybrid reference price, weighted between the day-ahead and longer-term markets, rather than strictly day ahead as it is now. Alternatively, the reference price could be based on a weighted volume average that goes back as far as one month.

From an ancillary services perspective, schemes that directly expose generators to market signals (e.g. capacity-based scheme) or indirectly align generators' incentives to market signals by decoupling support from metered output (e.g. Deemed Generation CfD) will incentivise generators to provide services if is economically efficient to do so.

Another possible reform being considered under REMA is the further co-optimisation of energy and frequency-related ancillary service products under centralised dispatch and scheduling, wherein an algorithm decides which product(s) is most economically optimal for the system and price optimal for the generator. Services that cannot be co-optimised with energy such as stability and reactive power would need to be procured separately. This means that wind and solar asset operators and traders wouldn't need to hedge their bets as to whether value is greater in the ancillary services and/or energy markets. Instead, they would submit unit-based complex bids with cost information for different services/products and allow the centralised algorithm to select the optimal market outcomes for the generator under the competitive market arrangements.

This paper makes no assumptions regarding the future outcomes of the REMA programme on incentive arrangements for renewable assets. For further, and up to date, information on REMA please visit https://www.gov.uk/government/collections/review-of-electricity-market-arrangements-rema

2.2.3. Power Purchase and Land Agreements

Renewable operators have told us that most solar and wind generators and farms are built under long-term land and power purchase agreements (PPAs). In these agreements, an energy supplier draws up an agreement with the generator to supply power to them, giving the generator a hedged source of revenue. This agreed PPA price can be used as part of the investment case for the creation of a new site of generators. Very often PPAs have an explicit clause that precludes non-mandatory ancillary service or Balancing Mechanism participation. This clause is included by the supplier because any time that the asset spends delivering ancillary services takes away from time spent generating power for the supplier with which they are contracted.

Generators are typically happy to agree to PPA contracts with suppliers that prevent ancillary service participation because it does not make up a significant part of the business case for a generator. Ancillary service contracts are often short, with competition meaning that there is no guarantee that they will win contracts. The revenue stream is therefore not seen by many generators as being significant enough to incentivise legal efforts to allow for ancillary service provision in the PPA contract.

Once set up, derogations and renegotiations to terms under these agreements are costly due to high legal fees, or difficult to execute as land agreements may specify particular revenue streams for assets party to it. So even where a business case can be made in which ancillary service participation would be more profitable than alternatives, legal costs to change the contract act as a barrier.

2.2.4. Power Purchase and Land Agreements Outlook

If revenues associated with ancillary service provision are made more attractive and accessible for renewable energy asset owners, land agreements and PPAs may also expected to evolve to enable participation for assets built on leased lands.

Since the fundamental barrier is that there is little economic incentive to initially specify or re-negotiate PPA contracts to provide the freedom to participate in ancillary services markets, the removal of other barriers will increase the likelihood of generators prioritising this in contracts. Providers noted that we have seen an industry trend toward shorter duration PPAs in some cases, which will also give more generators the freedom to participate if incentives change and as contracts expire.

2.2.5. Revenue Uncertainty

Another challenge to participation in ancillary service markets for solar and wind providers was highlighted to be lack of clarity about the medium and longer-term potential revenue certainty or future technical requirements at the project development stage. This particularly affects wind generators where investment decisions are made further ahead of operation to invest in capabilities to provide fast-acting services. As technical capability for generators is embedded during the design phase, these assets may be built without the technical capability to provide response and reserve if sufficient clarity for the future regarding ancillary services is not available. The value signal for solar could be shorter term (18-24 months) versus 5-10 years for wind. Therefore, there may be a disproportionate impact on renewable technologies from this uncertainty versus some other technology types since investment decisions need to be made earlier.

2.2.6. Revenue Uncertainty Outlook

The GB energy system and the technologies that can provide ancillary services are evolving at a great pace, with inherent uncertainty existing for the future needs of the electricity system. That uncertainty reduces over time, and we are continuously seeking to improve the forward visibility of how our markets and technical requirements will evolve. With so many variables at play, there is a limit to the information that can be provided about how the technical requirements of ancillary services might evolve for very long timeframes.

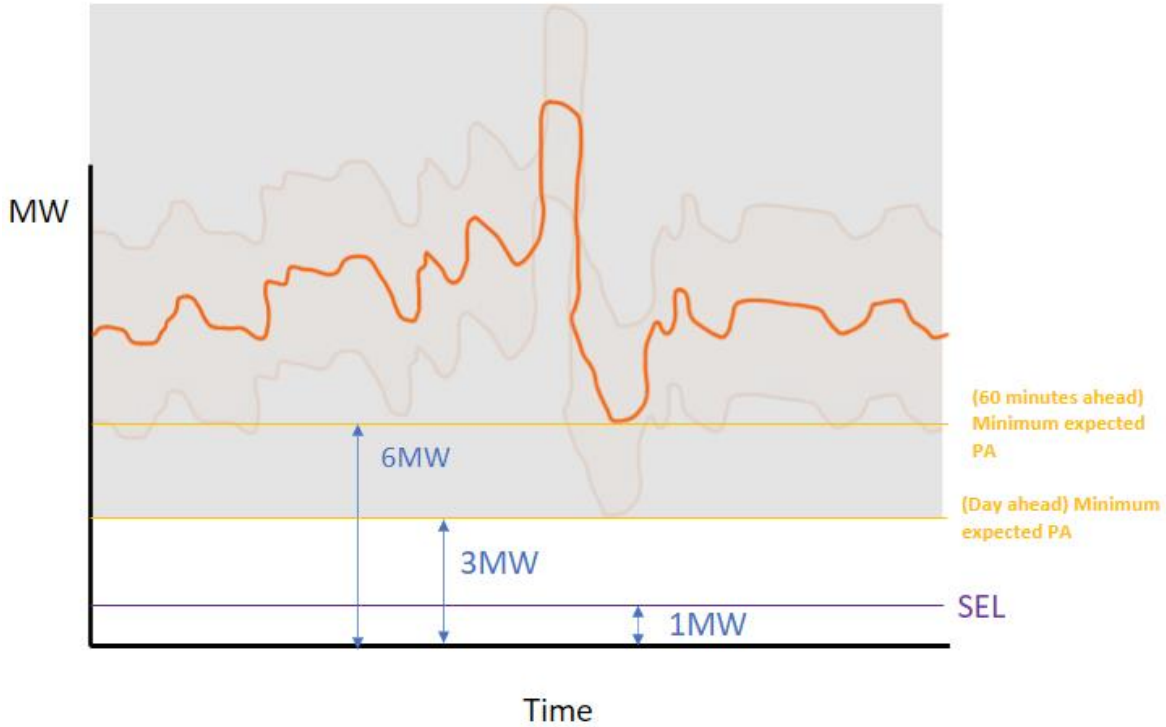
In addition, some technical requirements that may invalidate older units could be resolved by upgrades to the unit rather than having to completely replace them. Invertor upgrades are an example of being able to reconfigure older renewable units to new specifications.

2.3. Market/Service Design Barriers and Future Outlook

2.3.1 Day Ahead Procurement

Market participants in response and reserve markets are required to bid capacity (the amount of response/reserve they're able to provide) in auctions at the day-ahead stage. Weather dependent assets find it challenging to accurately forecast their output at the day-ahead stage. To mitigate the uncertainty risk around changing forecasts on the day where there may not be enough head or foot room to provide the service, providers may feel compelled to submit a lower, more conservative, capacity in response and reserve markets, which in turn results in potential loss of revenue.

In the following example of a wind farm's expected output (PA – Power Available) for a given time period, the minimum predicted generation at day-ahead stage, is 3MW. As its Stable Export Limit (SEL) is 1MW, it can be confident to deliver somewhere between 1MW and 3MW at all times.



In terms of response and reserve, it could provide 2MW of downward response if at full delivery (3MW), or could have up to 2MW of headroom if generating at 1MW SEL. As day-ahead stage estimates could be inaccurate, a provider may bid a risk-adjusted 2MW capacity in ancillary service markets to be sure to be able to provide the service at its lowest point of generation. However, at 60-minutes before delivery, when providers are required to submit final baselines, the generator could find that the minimum expected generation for that period would be 6MW. Having committed 2MW of response/reserve capacity at day-ahead stage, the generator would stand to lose revenues from providing an additional 4MW of service. It would be possible to sell this energy in the spot market instead where energy is bid in and sold close to real time. However, there is no guarantee that such a bid would be accepted and prices that a generator might receive are variable and not guaranteed to make up for the loss of potential ancillary service revenues. From a NESO perspective, this also reduces the available capacity that could be utilised in our services.

Challenges of accurate day-ahead forecasting mean providers price in risk and 'de-rate' capacity day-ahead, in turn increasing the price they bid for the service.

2.3.2. Day-ahead Procurement Outlook

We currently procure static firm frequency response, dynamic response services, and reserve services day-ahead. We are considering the benefits of a closer to real time (eg intraday or real-time) procurement of services, whether in addition to or instead of the day-ahead markets.

Implementing a closer-to-real-time procurement approach can offer renewable generators greater certainty regarding their ability to provide ancillary services. This is achieved through factors such as more precise weather forecasts closer to real time, enabling improved accuracy in predicting their capacity.

For renewable energy providers with an intermittency attached to generation, generation profiles could change in the matter of minutes and hours. Prediction of weather conditions, and therefore their available level of generation, would allow generators to be able to submit more accurate baselines, and therefore not need to underestimate generation due to weather variation uncertainty. Generators that do not have to underestimate their capacity can submit more generation consistently in our response and reserve markets, and the markets will therefore yield higher revenues for them.

We have begun engagement with industry on the case for closer to real time frequency response procurement in 2025. We will be considering this as part of a wider review, in which we also consider making changes to MFR (Mandatory Frequency Response), a service we activate in real-time, through month-ahead capacity auctions. If there is a case to do so, associated changes to enable closer to real time response procurement could be implemented as early as 2027 or 2028.

Centralised dispatch and scheduling (as detailed in 2.2.2.) may be an alternative option to address this issue, as energy/reserve optimisation and settlement would be in a real-time market.

2.3.3. Pre-Qualification and Testing

Engagements with small-medium solar and wind providers suggested that pre-qualification and testing for NESO's ancillary services provides a process and cost challenge for these suppliers. Specifically, the duration test is difficult for solar and wind providers as these are weather dependent assets. For testing appointments, it can't be guaranteed that a given day will be sunny or windy enough to give an accurate baseline.

2.3.4. Pre-Qualification and Testing Outlook

It is important to NESO to enable the participation of as many different technology types as possible in our markets. As other, more fundamental, market barriers discussed in this paper are addressed NESO will review testing and pre-qualification procedures to identify improvements that would address these concerns.

2.3.5. Baselines

Assets, referred to as units, that are participating in response and reserve services need to nominate an operational baseline one hour ahead of real time. This should be the best estimate of what the unit will be doing at the time. For renewables it can be challenging to accurately predict at one hour ahead of real time what this baseline will be.

Units submit an operational baseline ahead of time that should, alongside the service they will have delivered in real time, be close to the active power that they submit in their performance monitoring data after delivery. In Frequency Response units also submit a baseline after delivery. Delivery of the service is measured as the difference between the active power and baseline values submitted after delivery.

2.3.6. Baselines Outlook

For the new Quick Reserve service, NESO is proposing to allow Power Available (PA) to be used as the Final Physical Notification (FPN) for intermittent power sources. The challenge of providing a baseline in advance of real time should therefore not be an issue.

Performance of service delivery for Frequency Response uses a baseline submitted after service delivery. Therefore, the challenges with one hour ahead baselines should not impact service participation.

For the post-delivery baseline there are options that could be explored to enable renewable participation in ancillary services. It is possible that the Power Available (PA) signal, or a value derived from this, could be used for wind generators. PA is the maximum MWh output a generator could produce if its operation is not affected by control actions. Renewable generators are required to submit a real-time PA to NESO control room currently.

2.4. Technical Barriers for Wind and Solar

Based on our engagement with renewable generators, it appears that many of them have the technical feasibility to participate in ancillary services. However, older generators (likely predating 2017) lack the inherent capability for fast-acting response and would require retrofitting to meet the necessary requirements.

The technical parameters of these services are defined to meet system security needs and are therefore unlikely to be adapted for the purposes of widening participation alone.

3. Challenges for Interconnectors

3.1. Introduction to Interconnectors

At present, GB has an installed interconnector capacity of 9.8GW, with a target of adding another 11.7-12.5GW by 2030[3]. Interconnectors currently offer various services to NESO, including emergency services. Enabling greater participation of interconnectors in ancillary services markets can lead to enhanced system security and lower costs to consumers.

The revenue model for most interconnectors in GB is based on selling capacity to traders in pay as clear auctions. The traders arbitrage energy from one side of the interconnector using the capacity that they have bought, creating a profit from the difference in energy prices. Successful bids from traders on interconnectors' capacity auctions are typically close to the difference in energy prices, giving them a small profit whilst the interconnector operators themselves keep the monopoly rent from the arbitrage. However, there are scenarios where a portion of interconnector capacity is not allocated to arbitrage related activities, since energy prices between interconnected countries are too similar for it to be commercially viable. This capacity could potentially be allocated to participation in GB ancillary services markets.

Challenges for interconnector participation in ancillary service markets can be considered as a hierarchy. There are fundamental issues of commercial viability and system security of interconnected systems which will need to be resolved before value can be realised from addressing issues such as day ahead procurement and technical parameters.

It is worth noting that a pilot unilateral dynamic frequency response service, in the direction of GB via BritNed, was trialled in 2017. However, the trial was discontinued with no options for enduring adoption of this GB-response sharing service identified due political, regulatory, and commercial challenges. Specifically, a concern was expressed that the GB system was gaining an operational benefit from the EU system without mitigating measures being in place in EU markets. This was also, coincident with the creation of EU balancing codes/ platforms designed to harmonise and increase universal access to balancing products between all EU TSOs.

[3] These figures are taken from our Future Energy Scenarios data workbook, which can be accessed here: FES Documents | ESO (nationalgrideso.com)

3.2. Commercial Challenges and Future Outlook

3.2.1. Energy Payment

Participation of an interconnector in an ancillary service market such as Frequency Response or Reserve necessitates the removal or injection of energy from the interconnected system. During the activation of an ancillary service, an interconnector deviates from its nominated flow pattern in order to provide energy as response or reserve. This deviation creates an energy imbalance.

Historically, GB has held interconnectors financially neutral when this imbalance occurs with NESO compensating the interconnected TSO according to a price specified for the relevant service in the interconnector frameworks, such as the BASA (Balancing Services Agreements). The BASA is a tripartite agreement involving the two system operators and the interconnector operator. It encompasses terms and conditions that govern the pricing of energy for the provision of services. The price is set in advance to cover the system operator obtaining the volume of energy imbalance. This value is generally set to protect the TSO from the impacted system from potential losses in unfavourable scenarios and subsequently is not an attractive price for NESO compared to competitive ancillary services auctions.

An alternative arrangement exists whereby the interconnector may participate in the auction and compensate the impacted TSO through paying the imbalance price. When an interconnector does not follow its nomination, the interconnector operator will be exposed to imbalance at both ends as its contracted energy volume does not match its physical production or consumption. The imbalance price is not fixed as it is a function of the market dynamics in each system. In many scenarios, the imbalance price calculation is likely to yield a price that is lower than prices currently stipulated in BASA arrangements, enabling interconnectors to be competitive in ancillary services auctions.

Another variable to consider as part of the energy payment challenge is the kind of ancillary service involved. Services that have a low volume of energy delivery, such as the DC (Dynamic Containment) response service, would be much easier to build a commercial case for, as the imbalance price paid would be lower as a result.

3.2.2. Energy Payment Outlook

Through discussions with interconnector operators, we understand that a commercial case can be made for participation in ancillary services markets in the case that imbalance prices are applied to account for the energy imbalance on the impacted TSO as a result of services delivered. Such arrangements would need to be agreed between the interconnector operator and both TSOs at terms acceptable to all 3 parties. The services and pricing arrangements agreed would need to be reflected in the BASA arrangements. We understand that there are no structural or legal barriers to this approach.

Using the this approach the interconnector operator could bid into ancillary service auctions at a price they believed attractive compared to the predicted value of compensating the TSO at the other end of the interconnector.

3.3. Service and Market Design Challenges for Interconnectors

3.3.1. Day-Ahead Procurement of Ancillary Services

As described in the introduction, an interconnector generates most of its revenue by selling capacity to traders in cross-border capacity auctions over a range of timescales, with capacity nominations occurring after capacity auctions at both the day ahead and intraday timeframes. There may be periods where energy prices in GB and Europe are sufficiently similar for energy arbitrage not to be profitable. This may leave interconnector capacity unallocated or associated revenues unattractive. In these cases ancillary service market participation may be considered as an alternative.

As per the Trade and Cooperation agreement, the wholesale energy market is required to have the maximum available capacity, subject to two conditions: ensuring secure system operation and optimising system efficiency. Interconnectors that NESO have engaged with suggested that they may therefore be unable to offer firm capacity at the day ahead stage into ancillary service markets. Therefore, interconnectors will miss being able to bid in capacity within our procurement timeframe.

Closer to real time procurement of ancillary services would mean that interconnectors can observe this interpretation of the TCA and still bid unsold capacity into ancillary service markets.

3.3.2 Day Ahead Procurement Outlook

Closer to real time procurement of ancillary services would give interconnectors the opportunity to decide to bid unreserved capacity into ancillary service markets. If energy price differences between two connected countries are low, traders will be unable to make a profit from arbitrage and choose not to bid into the market. After intraday capacity auctions are completed, there is then scope for interconnector operators to bid remaining capacity into response and reserve service provision.

As mentioned in the renewables section for closer to real time procurement, we are currently exploring this for our frequency response products with possible implementation as early as 2027 or 2028. From our engagement with GB connected interconnectors, auctions as close to real time as possible, or at least 4 hours ahead of real time, would be a reasonable timeframe for interconnectors to be able to make an informed decision on whether to participate with capacity weighed against other revenue streams.

3.4. Technical challenges for Interconnectors

3.4.1. Operability Impact on the Connected National Electricity System

An interconnector delivering an ancillary service at one end will see an approximately equal and opposite change in power at the other end. This impacts the neighbouring TSO (and other TSOs in the same synchronous area), their control area and potentially their system frequency and use of response and reserve services. This may cause system security issues for connected TSOs particularly if both national electricity systems are experiencing frequency or margin challenges.

3.4.2. Operability Impact outlook

A comprehensive set of rules is needed to govern interconnector behaviours in ancillary services markets, as removing or injecting energy during times of system stress may otherwise have unpredictable impacts and worsen system security. Whilst there are currently not timelines for resolution, rules around cross-border ramp and frameworks for frequency events are issues being discussed with GB and EU TSOs via the ISA (Inter-Synchronous Area) UK-EU harmonisation meetings.

3.4.3. Deadband, small linear delivery range

EU balancing regulation System Operator Guidelines (SOGL) Article 55, as retained in GB regulation, stipulates that there be a deadband on our dynamic response services. This deadband exists for delivery of frequencies of 50Hz ±0.015Hz. It also stipulates, for deviations between 0.015Hz and 0.2Hz, there is small linear delivery. This small linear delivery range is where the delivery linearly increases from zero until the knee point at 0.2Hz.

Below is a summary of frequency behaviours expected of dynamic response participants in the DC market.

Service specification	Details
Deadband delivery	0% (+/- 0.015Hz)
Small linear delivery	Between 0.015Hz and 0.2Hz (maximum of 5% at 0.2Hz)
Knee point activation	+/- 0.2Hz is 5%
Full delivery	+/- 0.5Hz is 100%
Linear delivery knee point	0.2Hz
Full activation	0.5Hz
Full delivery	1s (but no faster than 0.5s)

Interconnector operators have identified the deadband and small linear delivery as a challenge. The key issue is that regular activation of very small volumes drives an increase in controller logic complexity, from how often an interconnector is likely to be activating in this range, which could also have adverse effects on the interconnector. Furthermore, frequent activation is likely to be a further challenge to alignment on operational protocols with interconnected TSOs.

3.4.4. Deadband, small linear delivery outlook

This topic is likely to be relevant in discussions related to the operational challenges articulated above as regular, small linear delivery may exacerbate operational concerns regarding cross-border ancillary service provision. In that context NESO will engage industry and Ofgem as appropriate to review the deadband arrangements in GB ancillary services as UK-EU harmonisation arrangements evolve.

4. Conclusions and Next Steps

Wind, solar and interconnectors all face significant challenges to participation in GB ancillary services markets. The most significant of these sits outside of direct NESO control.

Through REMA and the Inter-Synchronous Area working groups these issues are being actively explored. However, outcomes in both cases are uncertain at this time and this report makes no assumptions regarding them.

However, there are several actions currently under consideration or being undertaken by NESO that can run parallel to the consideration of these underlying challenges. If and when implementation dates for solutions are proposed, the NESO can align its own timelines to these events. In this way, challenges can be addressed in a coordinated fashion unlocking the possibility for participation for wind, solar and interconnectors.

Industry engagement by NESO to explore the case for real time procurement of response and reserve has begun in 2025. We will also review service specifications, including baseline methodologies, deadbands and small linear delivery ranges on balancing services to ensure that we are supporting the widest number of technology types possible whilst still maintaining the functionality, and compliance, of these products. When appropriate incentives are in place, interested parties may be encouraged to explore resolution to other challenges, including those related to power purchase agreements.

We do not plan to publish a further stand alone report on this topic but will share an annual update on the signposting progress against the challenges identified in this report through the NESO's annual Markets Roadmap publication. The ultimate aim will be to ensure that GB ancillary services markets are accessible to the widest range of technology and business model types to ensure the operation of efficient markets that meet the operational needs of a zero-carbon electricity system.

If you would like to send us any comments or discuss any of the issues covered in this report please contact us at: box.marketsengagement@nationalenergyso.com

Appendix 1: Challenges and Future Outlook tables

Below is a summary of the challenges identified as part of this work, with the future outlook next to each barrier.

Wind and Solar challenges	Future Outlook
Economic incentives. CfDs incentivise units to maximise generation output. Participating in ancillary services means reducing generation output and therefore forgoing CfD revenues, which is uneconomic due to strike prices exceeding response and reserve revenues.	REMA reform options for CfDs. REMA and subsequent reform of the CfD scheme could align generators' incentives to market signals, including those for ancillary services.
PPAs and land agreements. Majority of PPAs and land agreements preclude the participation in ancillary services of generation assets.	Expectation that parties will explore including ancillary service provision in contract terms when it becomes economic.
Revenue uncertainty. The investment timeframe for renewables means that it is hard for renewable generators to make investment decisions solely based on ancillary services, since the technological standards for ancillary services change over time.	NESO is continually seeking to improve the forward visibility of how our markets evolve.
Day ahead procurement. Day ahead markets and the associated requirement to be able to forecast output effectively are a challenge for renewable providers.	Closer to real time procurement for response products would reduce forecasting uncertainty generators potentially enabling renewable generators to submit more generation into our markets. Engagement on this topic will begin in 2025 with potential implementation as early as 2027
Pre-qualification and testing. Renewables struggle with giving accurate readings on baselining tests due to weather variation on testing dates.	NESO will review our testing procedures as other barriers are removed.
Baselines. It is difficult to predict a generation baseline for a renewable asset at 1h ahead of real time to submit as an FPN.	1h ahead baselines are not a barrier to market participation as post-event baselines are used for performance monitoring purposes. NESO will explore uses of Power Available as a performance baseline for ancillary services from wind generators as and when incentive reform indicates it is necessary to do so.

Technical barriers. No technical barriers have been identified.	Participation is technically possible.

Interconnector challenges	Future Outlook
Energy payment. In order to utilise interconnectors directly in ancillary services, energy leaving one TSO's electricity system needs to be paid for either by the procuring TSO or interconnector. However, current BASA defined prices for accounting for energy may be uneconomic.	Alternative pricing arrangements such as default to system imbalance price may be negotiated to enable interconnectors to be competitive in ancillary services markets.
Day ahead procurement of ancillary services. The TCA specifies that the maximum level of capacity on interconnectors should be made available for arbitrage. This makes it potentially challenging for interconnectors to justify bidding capacity into ancillary service markets at the day ahead timeframe, before traders have had the chance to participate in intraday capacity auctions.	NESO is currently investigating closer to real time procurement of ancillary services which may improve the ability of interconnectors to use unreserved capacity at the intraday stage for ancillary service provision. Engagement on this topic will begin in 2025 with potential implementation as early as 2027
Operability impact on the connected country's TSO. Removing or injecting energy during times of system stress may have unpredictable impacts and worsen system security.	Interconnectors need a clear set of rules to govern emergency frequency scenarios so that each national electricity system can plan accordingly. Rules around cross-border ramp rates and frameworks for frequency events are part of the live issues being discussed with EU TSO via the ISA (Inter-Synchronous Area) GB-EU harmonisation meetings.
Deadband, small linear delivery range. Between 0.15hz and 0.2hz is a range of small linear delivery for our dynamic response products. Requiring delivery in the first stage may be infeasible for interconnectors, due to the increase in controller logic complexity. Frequent activations as a result of this range could be seen as an issue by TSOs.	NESO will engage industry and Ofgem as appropriate to review the deadband arrangements in GB ancillary services.