Contracts for Difference Team
Department of Energy Security and Net Zero
3 Whitehall Pl,
London
SW1A 2AW
Delivered via email

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To whom it may concern,

Consultation Response: Further reforms to the Contracts for Difference scheme for Allocation Round 7

Scottish Renewables is the voice of Scotland's renewable energy industry. Our vision is for Scotland leading the world in renewable energy. We work to grow Scotland's renewable energy sector and sustain its position at the forefront of the global clean energy industry. We represent over 360 organisations that deliver investment, jobs, social benefits and reduce the carbon emissions which cause climate change.

Our members work across all renewable energy technologies, in Scotland, the UK, Europe and around the world. In representing them, we aim to lead and inform the debate on how the growth of renewable energy can help sustainably heat and power Scotland's homes and businesses.

Allocation Round 7 (AR7) of the Contracts for Difference (CfD) scheme will be crucial for achieving the UK Government's clean power mission. The level of ambition being signalled by DENSZ for the allocation round in recognition of this is very much supported by industry. The UK Government's intention to ensure Test and Demonstration (T&D) floating offshore wind projects are secured in AR7 is also particularly appreciated given the importance of these projects for the future development of the floating offshore wind sector.

Scottish Renewables therefore welcomes the opportunity to provide feedback on the UK Government's proposals of potential changes to the CfD for AR7. A summary of our responses to the three key proposals within the consultation is provided below. However, we first wish to highlight the importance of wider reforms in ensuring AR7 is a success.

The unprecedented ambition the UK Government has shown for turning the UK into a clean energy superpower has been a shot in the arm for the renewable energy sector. The UK Government's commitment to its clean power mission has initiated major reforms across multiple policy and regulatory frameworks, from reordering the connections queue to reforming network charges to measures to improve the speed and coordination of planning processes. The Review of Electricity Market Arrangements (REMA) is also still underway, with as yet no clear sign of what the outcome will be for GB's future electricity market.

Many of these reforms are due to come to a conclusion this year and indeed the need to provide clarity to potential bidders ahead of AR7 is the reason why some of these programmes are moving at the pace that they are. The result of AR7 will therefore mark the culmination of several reform

24 St Vincent Pl, Glasgow, G1 2EU
0141 353 4980 | @ScotRenew
www.scottishrenewables.com

initiatives and the success of the auction will depend on the timing and outcome of wider policy decisions taken over the course of this year.

The outcomes of two policy programmes in particular will be crucial for ensuring the success of AR7 – REMA and network charging reform. We discuss each in turn.

REMA

Through REMA the UK Government is considering two broad options for market reform: a move to zonal pricing and a Reformed National Market (RNM). This summer, the UK Government is due to announce a decision on which path will be taken.

Despite being considered under REMA for almost three years, the UK Government has not provided a model of its preferred zonal market design. There is therefore still very little clarity on what a move to a zonal market would mean in practice. Key details for understanding the impact of a zonal market on a project such as the number of zones, the process for setting and resetting zonal boundaries, trading and hedging arrangements and system balancing processes are still unknown. Similarly, there has been little firm detail provided regarding the scope, eligibility and design of transitional arrangements and the grandfathering protection that would be provided to existing assets and investments.

Nevertheless, whatever the level of detail the UK Government would be able to provide upon an announcement to introduce to zonal pricing, the simple fact remains that moving to a zonal market would create significant additional risk and uncertainty for investors at the precise time that the UK needs to attract an average of £40 billion per year between 2025-2030 to deliver on its clean power mission. This would lead to significantly increased strike prices in AR7 as well as in future allocation rounds. Depending on the timing and level of detail provided upon an announcement to move to zonal pricing, developers may not be able to build realistic revenue forecasts for their projects, in which case there would be a real risk that eligible projects opt not to bid in AR7. This would both increase costs for consumers, jeopardise 2030 targets and delay the benefits a clean power system will provide.

The risks to AR7 from a potential move to zonal pricing are clear. In the longer term it is Scottish Renewables' view that any benefits from zonal pricing are likely to be significantly outweighed by the additional costs a zonal market would create. We therefore believe that **the single most effective action the UK Government could take to ensure the success of AR7 and ultimately deliver on its clean power mission is to rule out zonal pricing without delay and commit to a programme of evolutionary market reform through a RNM.**

Network charging reform

Scottish Renewables has consistently called for reform of Transmission Network Use of System (TNUoS) charges. Current TNUoS charges are unpredictable and volatile, and the increasing divergence in TNUoS charges across GB is threatening to block the development and continued operation of renewable energy generation in Scotland.

With the Clean Power 2030 Action Plan confirming that significant new renewable generation in Scotland will be required to deliver on clean power targets, the current TNUoS charging regime could therefore derail progress towards achieving the UK Government's clean power mission and lead to significant, unnecessary additional costs to consumers unless it is reformed.

This led Ofgem to publish an open letter on September 30, 2024 directing NESO to implement a temporary cap and floor on wider TNUoS charges. Several models for how a cap and floor could work have been proposed, with Ofgem scheduled to announce which solution, if any, it will take forward by July 1, 2025, for implementation by April 1, 2026. Proposals to improve the cost reflectivity of TNUoS charges by removing the existing Locational Onshore Security Factor uplift are also being considered.

Whatever approach is taken, **unless a meaningful reduction in TNUoS charges for northern projects is delivered and then maintained by REMA reforms, there is a real and immediate risk that Scottish generators will not be able to compete AR7 and future allocation rounds.** This scenario would mean projects required for Clean Power 2030 would be terminated, harming the interests of UK consumers. Clean Power 2030 targets, the successful delivery of the ScotWind leasing round and Scotland's move to a renewable energy-based energy system would be at risk, jeopardising the UK's energy security, economic growth and investment in local communities.

Summary of response to key consultation proposals

Relaxing CfD eligibility criteria for fixed-bottom offshore wind projects

Scottish Renewables does not support the proposal to relax CfD eligibility requirements to allow unconsented projects to participate in AR7. This proved the most controversial proposal in the consultation and there have been individual members which have expressed strong support as well as strong opposition to the proposals. However, a clear majority of the members which engaged with Scottish Renewables on this issue are opposed to relaxing eligibility requirements.

Scottish Renewables does not believe that relaxing eligibility is necessary to ensure sufficient auction competition. Whilst auction liquidity could be increased by relaxing eligibility requirements, between 14-16GW of consented offshore wind capacity could be eligible for AR7 if pending consent decisions are expedited. This would represent a record amount of offshore wind capacity eligible for an auction.

Similarly, we do not believe that allowing unconsented projects to secure a CfD would significantly impact their overall delivery timelines. Securing a CfD prior to obtaining consent could give projects greater financing confidence ahead of FID. However, project delivery timelines would still depend primarily on securing planning consent, supply chain availability and grid connection dates.

Unconsented projects are not necessarily 'immature', and some unconsented projects are at relatively advanced stages of development. However, there are nonetheless several significant risks associated with allowing unconsented projects to compete in CfD auctions. These risks include potential non-delivery of projects if bids turn out to be too low, inefficient use of CfD budget if planning consent is refused and higher consumer costs due to risk premiums being factored into bids. This risk would be passed onto the supply chain with the impacts potentially being compounded by unconsented projects not being able to submit ambitious Clean Industry Bonus (CIB) proposals. Scottish projects could also be disadvantaged due to the Scottish planning process not following a fixed timeline, unlike the process for English and Welsh projects.

Given the limited potential benefits and significant downside risks, Scottish Renewables does not believe this proposal should be taken forward. However, if the UK Government proceeds despite these concerns, the Non-Delivery Disincentive (NDD) must be maintained for unconsented projects to mitigate the risk of speculative bids. Whilst it may be necessary to provide unconsented projects with a degree of flexibility over delivery milestones and contractual obligations, equivalent flexibilities should be afforded to consented projects to ensure fair competition between consented and unconsented projects. Additionally, if the UK Government decides to implement this proposal for fixed bottom offshore wind, it should also consider doing so for other technologies such as floating offshore wind to maintain consistency across technologies.

Scottish Renewables' view on this issue is not shared by the entirety of our membership and there is a minority of Scottish Renewables members which support the proposal. However, overall, we believe that the risks of allowing unconsented projects to participate in CfD allocation rounds do not exceed potential benefits and therefore that the proposal should not be implemented. Ultimately, it would mean that consented "shovel ready" projects could lose out to unconsented projects with greater cost uncertainty and higher non-delivery risk which in turn could risk 2030 targets. Instead, we believe that expediting planning processes would be the best way to meet the policy objectives set out in the consultation.

Amending the budget publication process and information received

Scottish Renewables supports the policy intention to maximise deployment, ensure the auction budget is used efficiently and provide visibility of future procurement. However, we believe the consultation proposals are more complex and higher risk than alternative measures that would achieve the same objectives.

Scottish Renewables supports publishing a capacity ambition ahead of the auction, but an ambition that can be revised downward would not provide the same confidence as the current budget notice which can only be revised upward. While we support the Secretary of State receiving some degree of information to understand how much additional capacity would be procured for a given level of budget increase, the Secretary of State should not be granted access to a full anonymised bid stack as individual offshore wind projects could still be identified from price and capacity information.

The published capacity ambition should instead function as a binding minimum procurement level. Rather than providing a full anonymised bid stack, NESO could inform the Secretary of State about required budget increases to procure marginal projects without revealing detailed bid information. Soft budget and capacity caps could also be used to prevent inefficient budget spend. Additionally, the UK Government should support long-term certainty by publishing a forward schedule of allocation rounds with five-year rolling capacity targets and indicative 2035 and 2040 targets for key technologies.

Increasing the contract term for future CfD projects

Scottish Renewables strongly supports extending CfD contract lengths. New renewable energy projects are being built with increasingly long operational lifespans whilst, at the same time, potential revenues in the 'merchant tail' are becoming increasingly uncertain. This means that new renewable energy projects are considerably more exposed to market price risk than was the case when the CfD was first introduced.

Extending contracts to at least 20 years would reduce the exposure of CfD-supported generation to market price risk which in turn would significantly lower capital costs, resulting in reduced strike prices that would deliver net savings to consumers. Longer contract terms would also help shield assets from significantly increased price risk if zonal pricing is implemented.

It is essential that the UK Government makes a definitive decision on contract length before AR7 begins. Postponing this decision until AR8 could cause developers to delay project submissions in the hope of securing a more favourable contract, potentially reducing AR7 participation and driving up strike prices.

Similarly, for all potential changes to AR7 as well as core auction parameters, the UK Government should aim to give potential bidders as much advance notice of the finalised design of the auction as possible. In terms of the timing of auction itself, the UK Government must align the AR7 timeline with wider policy decisions and announcements due over the course of this year to ensure projects are able to adequately account for these announcements when preparing their bids.

Scottish Renewables would be keen to engage further ahead of the design of AR7 being finalised and would be happy to discuss our response in more detail.

Yours sincerely,

Andrew MacNish Porter
Head of Economics and Markets
amacnishporter@scottishrenewables.com
Scottish Renewables

Consultation Questions

Chapter 1.3 - Support for floating offshore wind

1. Are there any further measures you believe are necessary to facilitate the Government's intention to support multiple Test & Demonstration scale floating offshore wind projects in AR7, whilst considering potential impacts on auction dynamics? If so, what and why?

The UK Government's recognition of the value of Test and Demonstration (T&D) scale projects in growing supply chains, promoting innovation and building investor confidence is warmly welcomed.

We support the UK Government's intention to secure multiple T&D scale projects in this year's auction and agree that the AR6 Administrative Strike Price should not be lowered.

It is crucial that T&D projects which were eligible for AR6 are successful in AR7 as there will be most value in deploying these 'stepping stone' projects ahead of the commercial scale projects which will be bidding for a CfD from AR8 onwards. The three T&D projects which are currently eligible for AR7 collectively offer diversity in size, location, foundation type, port facilities and technology choice. This diversity will serve as vital learning for future commercial scale projects. As such, we believe that all eligible T&D projects should be secured in AR7. The wider benefits these projects will deliver in terms of learning and long-term cost reduction exceed any potential cost savings from competitive tension in the auction.

We therefore recommend that a capacity minimum of 258MW for floating offshore wind projects 100MW or less is used for AR7, with a commitment to increase this minimum if more T&D projects become eligible for the auction. (258MW being the combined capacity of the currently eligible T&D scale projects: Pentland, 100MW; Erebus, 100MW; and Blyth 2, 58MW.)

Further measures to support floating offshore wind projects such as reducing the Required Installed Capacity to a minimum of 85% of the contracted capacity and extending the Longstop Period from 12 to 24 months to mirror fixed-bottom offshore wind should also be considered.

Chapter 2.1 - Relaxing CfD eligibility criteria for fixed-bottom offshore wind projects

2. Do you support the general proposal to relax eligibility requirements to enable projects to apply for a CfD while awaiting their planning consent? Yes, No, Unsure? Please provide any further comments to support your answer.

No. Scottish Renewables does not support the proposal to relax eligibility requirements to enable projects to apply for a CfD while waiting for planning consent.

Member views are not unanimous on this issue, and individual members have voiced both strong support and strong opposition to the proposals. However, a clear majority of the members which have engaged with Scottish Renewables on this issue, including both developers and supply chain companies, are not in favour of the proposals set out in the consultation.

The consultation states that the primary rationale for the proposal to relax eligibility requirements is to increase participation to ensure a more competitive auction. The consultation also suggests that relaxing eligibility could accelerate delivery of unconsented projects, thereby helping the UK Government to reach its 2030 clean power target.

However, on both these points, Scottish Renewables overall does not believe that relaxing eligibility criteria as proposed would deliver benefits which would outweigh the risks associated with allowing unconsented projects to participate in CfD auctions.

Regarding competition in AR7 specifically, we recognise the UK Government's concerns about the potential lack of competition due to the volume of capacity required as outlined in the Clean Power 2030 Action Plan. However, the delayed CfD application deadline, expected in late summer, should allow for the consent and therefore eligibility of 14-16GW of offshore wind capacity in time for the application window. To achieve this, both the UK and Scottish Governments must prioritise expediting the determination of several late-stage consent applications well ahead of the application window opening. This level of eligible offshore wind capacity would represent the largest ever in an allocation round, enabling the Government to secure even the most ambitious Clean Power 2030 scenario competitively without the risks associated with relaxing the eligibility requirements.

Similarly, we do not believe that relaxing eligibility will significantly accelerate the delivery of unconsented projects as, although the proposed relaxation of the eligibility requirements could enable unconsented projects to secure a CfD at an earlier stage and thereby enhance financing confidence ahead of FID, the delivery timeframe of a project will largely depend on the project obtaining planning consent, any associated planning conditions, securing the necessary supply chain and its grid connection date.

DESNZ acknowledges that relaxing eligibility requirements would come with significant risks, the risks identified in the consultation being:

- Bids by early-stage projects may turn out to be too low, which could result in non-delivery.
- Projects may be refused planning consent. This would prove an inefficient use of the CfD budget, especially if awards are at the cost of viable projects.
- Unconsented projects may include a higher 'risk premium' in their bids, due to increased uncertainty over project costs, which could result in higher costs to consumers.

Scottish Renewables agrees that allowing unconsented projects to compete in CfD auctions would carry these risks. Furthermore, Scottish projects would be at a distinct disadvantage because, while the Development Consent Order (DCO) process in England and Wales has been streamlined, with each stage following either a statutory or indicative timeline, this is not the case in Scotland. In addition, in Scotland, the time limit for initiating a judicial review of a Section 36 decision is three months from when the decision is made. In contrast, it is only six weeks in England and Wales, placing further risks on Scottish projects by comparison. As highlighted above, CfD eligibility requirements are not the core problem and considerations regarding allowing unconsented project to compete in CfD auctions should not detract from urgently needed efforts to speed up the planning process.

Whilst the consultation focuses on the risks of non-delivery and the potential for increased costs to consumers, Scottish Renewables would also highlight the implications of relaxing eligibility criteria for the supply chain:

- Immature projects locking in CfD contracts would significantly increase the risk of non-delivery and pass this uncertainty onto the supply chain which could jeopardise additional inward investment. The supply chain would need to make supply and capacity allocation decisions against a more uncertain backdrop, where projects with CfDs are no longer necessarily 'shovel ready'. Consented projects typically have advanced negotiations, or even agreed contracts, with suppliers for major components, filling factory slots and enabling planned investments. In contrast, unconsented projects would likely not be able to replace orders in a similar timescale.
- The proposal will place even greater demands on the UK's already strained offshore wind supply chain, likely leading to further bottlenecks and inflated prices as more projects seek Preferred Supplier Agreements or similar agreements prior to the auction. Suppliers could face managing potentially significant demand from unconsented projects while also managing a large volume of existing entrants with Clean Industry Bonus (CIB) applications and component supply offers.
- Unconsented projects that anticipated participation in AR8 are unlikely to have adequately engaged with the supply chain to develop high-quality CIB extra proposals for AR7. With the CIB application window soon closing on April 14th, this not only undermines the competitive process for the CIB auction but would also represent a missed opportunity for the UK's industrial and coastal communities which could have benefited from such additional investment.

Suppliers as well as developers have expressed concern over the proposal to relax eligibility requirements for these reasons. Indeed, there are no supply chain companies within Scottish Renewables' membership which have expressed support for these proposals. Overall, suppliers see the proposal as having a destabilising effect on the supply chain by adding risk to supply and capacity allocation decisions.

Whilst significant, the risks set out above stem primarily from the potential for immature projects to compete in CfD auctions. However, unconsented projects are not a homogenous group and projects which get to the point of submitting a planning application will be at varying stages of development. These risks could therefore be mitigated, although not eliminated, by measures to prevent immature projects from taking advantage of relaxed eligibility criteria. Indeed, some developers which have expressed support for relaxing eligibility requirements have made a point of highlighting that their projects are significantly advanced in terms of project design and procurement.

An additional measure to help ensure only mature projects take advantage of relaxed eligibility requirements, should they be progressed, could be to add a minimum pre-consent spend (e.g. 5-10%

of CapEx) to the eligibility criteria. This could reduce the risk of speculative projects entering the auction whilst increasing competition.

The risks outlined above should also be viewed in the context of the fact that submitting a planning application is already a significant undertaking of an offshore wind project. Historically there are few instances where planning consent has been refused and the risk of failing to gain consent has fallen as the sector has matured.

Similarly, although the proposed changes may negatively impact the quality of CIB bids, the CIB mechanism as designed is already a barrier to entry for unconsented projects in AR7. The application window for CIBs closes in mid-April and it is unlikely immature unconsented projects will have contracted with supply chain companies to the level required to meet CIB minimum requirements and to submit a CIB extra proposal.

Nevertheless, there is broad agreement that the ‘consent eligibility date’ identified in the consultation is set at too early a stage in both the Scottish and English/Welsh planning processes to sufficiently address the risk of immature projects submitting CfD bids. Allowing projects which have had their application for a DCO accepted for examination by the Planning Inspectorate (for English and Welsh projects) or have had to have applied to the Scottish Ministers for any required section 36 consent and marine licence(s) in respect of the proposed generating station, and public consultation commenced (for Scottish projects) could in fact create a perverse incentive for projects to rush a consent application in order to be eligible for a CfD allocation round.

The consent eligibility date would instead have to be set at a later point in the consenting process. However, due to differences in the Scottish and English/Welsh consenting processes, it is not clear that there would be a workable equivalent later intermediate point due to the Scottish process not following the same statutory timeline as the process for English and Welsh projects.

This points to a broader challenge in ensuring a level playing field between consented and unconsented projects. As a point of principle, if the UK Government decides to proceed with relaxing eligibility criteria it must do so in a way which ensures fair competition between consented and unconsented projects across both GB planning systems.

The consultation asks whether, if allowed to participate in CfD auctions, unconsented projects would require greater flexibility to accommodate uncertainty over planning timelines and outcomes so as avoid a situation where unconsented projects have their contracts terminated whilst awaiting planning consent. Specific flexibilities the consultation considers are:

1. Whether the Non-Delivery Disincentive (NDD) should be removed to allow unconsented projects to leave their contract early without penalty.
2. Whether unconsented projects should have the ability to defer their Milestone Delivery Date (MDD).
3. Whether other flexibilities, such as allowing generators to adjust their contract to accommodate planning conditions imposed on their contracts, would be necessary.

If unconsented projects are allowed to participate in CfD auctions, it is Scottish Renewables’ firm belief that the NDD should apply to unconsented projects as it currently does for consented projects. The NDD is essential for discouraging speculative bids and the risk of speculative bids would be higher from immature projects. Unconsented projects therefore should not be allowed to leave their contract early without penalty.

Projects are not obliged to bid pre-consent, and it would be a for a project's board to decide whether the project is suitably advanced for the risk imposed by the NDD to be acceptable when considering entering an allocation round. If the NDD is deemed an unacceptable risk for an unconsented project, it would be because it does not have sufficient confidence in being able to deliver at its bid price and/or meet contractual milestones, in which case such a project should not be competing in an auction where it could potentially win at the expense of a consented, 'shovel ready' project. In this sense the NDD would arguably have an even more important role in being applied to unconsented projects than the role it plays under the current framework. However, it should be noted that the NDD would only disincentivise, not prevent, immature projects from bidding for a CfD as whether or not a project decides to enter an allocation round would ultimately depend on the developer's risk appetite.

With regards other flexibilities, unconsented projects would likely need flexibility to defer their MDD in the case of exceptional planning delays. Similarly, unconsented projects would require flexibilities to allow post-consent adjustments. Such flexibility would be important for mitigating cost uncertainty being priced into CfD bids.

However, if the UK Government decides to proceed with this proposal and does grant flexibilities to unconsented projects, equivalent flexibilities should be afforded to consented projects to maintain a level playing field and avoid a perverse outcome where bidding with an unconsented is viewed as favourable due to being offered a more flexible contract.

As with consented and unconsented projects, level playing field concerns also apply across technologies. If the UK Government decides to relax eligibility requirements for fixed bottom offshore wind, developers of other technologies would have a legitimate argument that the same changes should be made across other technology classes.

The case would be strongest for floating offshore wind, given the size of the pipeline and both the UK and Scottish Government's ambitions for the sector. In terms of commercial scale projects, there is a particular imperative to deliver Targeted Oil and Gas (TOG) projects as soon as possible given their role in decarbonising oil and gas production. If a relaxation in eligibility criteria is extended to floating offshore wind, for TOG projects to be able to participate existing rules regarding requiring an option agreement would need to be altered to accommodate exclusivity agreements in case the Sectoral Marine Plan is not published in time for the AR7 application window opening. We would also note that any efforts to procure commercial scale floating offshore wind in AR7 should not come at the expense of procuring T&D projects, as we discuss in our response to Question 1.

However, these broader considerations would only relevant if the UK Government decides to proceed with relaxing eligibility requirements for fixed bottom offshore wind which, overall, is a proposal that Scottish Renewables does not believe the UK Government should implement. Whilst Scottish Renewables' view is not shared by the entirety of our membership, our position represents that held by a clear majority of our membership.

Ultimately, the proposals would mean that that consented, 'shovel ready' projects could lose out to unconsented projects which have greater uncertainty over project costs and carry a higher risk of non-delivery. Whilst not all unconsented projects are necessarily 'immature', we do not believe the proposal is necessary to ensure sufficient auction competition. Neither do we believe it would significantly accelerate project delivery timelines. In summary, we therefore do not view the potential benefits of this proposal as outweighing the associated risks.

3. The proposal outlines two options for the Consent Eligibility Date. Which option do you prefer? Eligibility proposal A, Eligibility proposal B, No preference? Please provide any further comments to support your answer.

Scottish Renewables has a weak preference for eligibility proposal B. However, in practice there will be very little difference in the amount of capacity which would be eligible under each proposal.

4. Are newly eligible (unconsented) projects likely to take advantage of the proposed relaxation of eligibility requirements? Yes, No, Unsure? Please provide any further comments to support your answer.

Whether or not unconsented projects take advantage of the proposed relaxation to participate in AR7 will remain a commercial decision and will depend on a range of factors including the flexibilities afforded in the CfD Standard Terms and Conditions and milestones, the maturity of the project (including the level of engagement with the supply chain) and the risk appetite of the developer.

Clearly, the greater the flexibility and the lower the penalties for non-delivery the more likely unconsented projects are to participate in the auction. However, this would encourage immature projects to bid speculatively in the knowledge they could subsequently cancel their contracts with minimal penalties and rebid in a later allocation round to attempt to achieve a higher strike price. Relaxing eligibility criteria to this degree could therefore slow the deployment of low-cost renewable generation rather than accelerate progress towards 2030 targets.

5. Is this change likely to reduce development timelines for newly eligible projects (either now, or in future once the change can be adjusted to)? Yes, No, Unsure? Please provide any further evidence to support your answer.

No. Although the proposed relaxation of the eligibility requirements could enable unconsented projects to secure a CfD at an earlier stage, their development timeline and reaching commercial operations will largely depend on the project obtaining planning consent, any associated planning conditions, securing the necessary supply chain and its grid connection date.

The proposed intermediate consenting point (i.e., 15 months before consent in England/Wales and 2 - 4 years before consent in Scotland) is set such that a project early in the consenting process could still deliver within the same timeframe if it waited until the next annual allocation round. This offers no real advantage in terms of project delivery. Considering the projected delivery timelines for the current pipeline of likely AR7 and AR8 projects, we do not believe this change will result in significantly more capacity being delivered before 2030 compared to the existing framework.

Additionally, the ORESS process in Ireland which permitted CfD awards prior to consent did not lead to expedited project FID. This experience suggests that awarding CfDs prior to consent in the UK would similarly have little impact on overall delivery timescales.

6. Are there any challenges or barriers a developer would face in preparing a bid for a newly eligible (unconsented) project compared to a consented project? Yes, No, Unsure? Please provide any further evidence to support your answer.

Yes. See also answer to Question 2.

Projects that have yet to achieve consent will not yet have sight of full project costs and will likely therefore include contingency (i.e. for undefined risk) in their bid price which, if successful, is passed on to consumers potentially pushing up the clearing price for all projects. Smaller projects are potentially disadvantaged in this process as there is less room to transfer risk. Immature projects locking in CfD contracts would also have significantly higher risk of non-delivery and pass this uncertainty onto the supply chain which could jeopardise additional inward investment.

Projects without a main consent will not know precisely what conditions will be applied to their development, including potentially costly mitigation and compensation requirements. The key unknowns currently, due to evolving government policy, are strategic compensation for seafloor and seabird impacts, and underwater noise mitigation through Noise Abatement Systems (NAS) such as bubble curtains. The UK Government (Defra) is also looking into an as yet unknown noise limit for construction potentially as soon as 2027 which, if enacted, will affect all projects bidding into AR7. This may significantly increase project construction but no clarity is expected before bids are made.

Additionally, the uncertainty surrounding unconsented projects could lead to higher financing costs. Investors and financial institutions may be more cautious when dealing with projects that have not yet secured planning consent which could result in higher interest rates or more stringent lending conditions. This could significantly increase the overall cost of the project.

7. Would the proposed changes have a positive, negative or neutral impact on supply chains? Positive impact, Neutral/No impact, Negative impact? Please provide any further evidence to support your answer.

See answers to Question 2 and Question 6.

Overall, suppliers see the proposal as having a destabilising effect on the supply chain by adding risk to supply and capacity allocation decisions. What the supply chain needs is certainty over project timelines. Unconsented projects (particularly those in Scotland where the consenting process does not follow a fixed timeline) are not able to provide this certainty to the degree that consented projects can.

8. Do you agree that the Non-Delivery Disincentive should apply to unconsented projects that fail to return a signed CfD contract by the statutory deadline? Yes, No, Unsure? Please provide any further evidence to support your answer.

Yes. See answer to Question 2.

The NDD is a crucial tool for discouraging speculative bids, mitigating non-delivery risk and under procurement in the auction. It should therefore be applied equally to all projects entering a CfD auction.

9. Do you agree that certain contractual obligations and milestones should be deferred or some flexibility permitted for unconsented projects until a planning decision is issued? Yes, No, Unsure? Please provide any further evidence to support your answer.

See answer to Question 2.

Unconsented projects would likely need to be given flexibility to defer contractual milestones to avoid viable projects being blocked by consenting delays which are outside their control.

However, to avoid creating an unlevel playing field, if flexibilities are afforded to unconsented projects then equivalent flexibilities would need to be allowed for consented projects. For example, if a consented project winds a CfD but subsequently has its consent decision subjected to judicial review then it should be granted similar flexibility over its contractual obligations and delivery milestones.

10. Do you support the following flexibilities in the CfD contract to accommodate unconsented projects:

a. Deferment of the Milestone Delivery Date until a planning condition is issued. Yes, No, Unsure?

Yes, provided equivalent flexibilities are afforded to consented projects.

Deferment should apply on a day-for-day basis for consenting delays. However, any extension to the MDD should be capped. This cap is essential to guarantee that projects are delivered within the specified timelines. All projects bidding into the CfD should be subject to the same risks and consider the likelihood of being able to deliver their project on time.

b. Ability to leave contract early without penalty if planning consent is delayed beyond a certain date. Yes, No, Unsure?

No.

c. Provision to allow unconsented generators to adjust their contracts to accommodate planning conditions imposed on their projects following consent approval. Yes, No, Unsure?

Yes.

11. Are there any other contractual obligations and milestones that you think should be deferred or granted flexibility not mentioned above? Please provide further details to support your answer

No, subject to further details and further consultation on required contract changes.

Our view at this stage is that other delivery milestones, such as Target Commissioning Windows and Longstop Dates, should remain unchanged. Unconsented projects participating in the CfD should only do so if they are confident in their ability to deliver within the specified windows.

Chapter 2.2 - Amending the budget publication process and information received

Budget Notice publication

12. Is it important to receive a monetary budget in advance of the sealed bid window? Yes, No, or Unsure. Please provide your view on whether it is important to receive a monetary budget in advance of the sealed bid window.

No, provided the published capacity ambition functions as a binding minimum level of procurement for the auction.

Scottish Renewables supports the intention of the proposals in this chapter, namely, to maximise deployment, ensure the auction budget is spent efficiently and give industry forward visibility of the amount of capacity to be procured in an auction.

However, Scottish Renewables has concerns regarding the consultation proposals and believes they are more complex and carry higher risk than alternative measures which would achieve the same objectives.

Scottish Renewables believes a capacity ambition should be published ahead of the auction as proposed as part of the consultation. However, as proposed, being an ambition which can be revised down as well as up, a published capacity ambition would not carry the same value as the budget notice (which can only be revised upwards) in giving confidence regarding the amount of capacity to be procured in an auction. Similarly, we support the Secretary of State receiving some degree of information to understand how much additional capacity would be procured for a given level of budget increase. However, we believe giving the Secretary of State visibility of an anonymised bid stack would carry significant, unnecessary risks as, for offshore wind at least, it would be possible to identify individual projects from price and capacity information even if bids were ostensibly anonymised.

Scottish Renewables therefore proposes the following reforms are implemented rather than those set out in the consultation:

- A capacity ambition that functions as a minimum for how much capacity will be procured in the auction (similar to how the budget notice currently functions) is published ahead of the auction. The Secretary of State could then revise the capacity ambition upwards once applications have been received, similar to the current monetary budget revision process.
- Instead of providing the Secretary of State with bid information, NESO informs the Secretary of State of the amount that the monetary budget would need to be increased to procure the marginal project for each technology and whether this marginal project would be sufficient to

meet the respective technology capacity ambition for the auction. Where procuring the marginal project still falls short of the capacity ambition, NESO should advise the Secretary of State how much additional monetary budget would be required to procure capacity aligned with the capacity ambition as published prior to the auction. The Secretary of State would then choose whether to increase the budget on this basis.

- Soft budget and capacity caps could also be used to prevent inefficient budget spend. However, we appreciate it may not be possible to introduce soft budget caps for AR7. This should be considered for future allocation rounds.

We would also highlight our support for the recommendations set out in RenewableUK's report, 'Revitalising the Contracts for Difference Scheme', including those relating to providing long-term certainty. We welcome that the UK Government has indicated its intention to publish a forward schedule for future allocation rounds, and we suggest auction capacity targets are published for each funding pot on a rolling basis five years in advance as well as indicative 2035 and 2040 targets for key technologies, as proposed in the report. These proposals should be implemented alongside measures to ensure market reflective auction parameters which are also recommended in the report.

13. Would replacing a monetary budget with a capacity ambition impact participation in the allocation round? Yes, No, or Unsure. Please provide your view on whether replacing a monetary budget with a capacity ambition would impact participation in the allocation round.

No.

Projects typically want to win a CfD as quickly as possible. However, if the Secretary of State had access to bid stack information then this could impact bidding behaviour.

If the capacity ambition becomes a de-facto capacity limit, this would impact participation in the allocation round. A binding capacity minima that cannot be subsequently reduced is the best approach to maximise competition in an auction.

Publishing a schedule of capacity ambitions for future allocation rounds could also increase the efficiency of project development as developers will be better able to plan ahead to target competing in a specific allocation round. This should encourage a steady pipeline of projects coming forward through annual allocation rounds which will help secure supply chain investment as well as allow developers to better manage their resources.

14. Would publishing a budget notice after the sealed bid window have a negative impact on:
  a. Competition and bidding behaviour: Yes, No, Unsure.

No, provided the capacity ambition is a binding capacity minima.

Bidders will submit sealed bids based on the information available to them at the time, which we believe should be a capacity minima and other core parameters such as the Administrative Strike

Price. Publishing the budget after the sealed bid window has closed would have little effect as long as the capacity ambition can only be revised upwards as it currently the case with the published monetary budget.

To ensure that publishing the budget after the auction does not damage competition, project approvals or optimal price bidding, confirmation of auction parameters is needed well ahead of the application window opening. To enable this government needs to provide:

- A clear view on auction parameters and the allocation framework as soon as possible.
- A clear view on auction timings – including expected application window opening dates.
- A capacity ambition for AR7, expressed as a minima for each funding pot.
- A clear auction schedule with capacity targets for five auctions in advance, linked to Clean Power 2030 targets and the Strategic Spatial Energy Plan (SSEP).

b. Boards / developer decision making timelines / processes and whether this could impose any unintended consequences / additional costs on developers: Yes, No, Unsure.

No.

c. Non-delivery/withdrawal from auction: Yes, No, Unsure. Please provide further evidence on this/these impacts.

No.

Expediting the allocation process for offshore wind

15. Are you in favour of the auction process being run for parts of the allocation round, whilst other parts proceed with an appeals process? Yes, No, Unsure. Please provide further evidence in support of your views

This could be useful for meeting Clean Power 2030 targets, as fixed bottom offshore wind projects will have longer lead-in times than other technologies (other than floating offshore wind). NESO and government would need to ensure sufficient foresight of the auction is provided to allow developers to prepare bids.

However, the allocation process for offshore wind should only be expedited if UK Government can give assurance that the rest of the auction would not be delayed relative to the timeline it would follow should this proposal not be implemented. The process for offshore wind should only be expedited if the budget and auction clearing process for Pot 3 was entirely independent of the other auction pots. By running the offshore wind auction early there is a risk that the budget setting process favours offshore wind projects and funding is reduced for the delayed pots. Clear binding capacity minima aligned with Clean Power 2030 targets could mitigate this risk.

In future, this approach could also be utilised for pot 1 technologies to help pot 1 run faster and more regularly

Removing restrictions on available auction information

16. Are you in favour of the Secretary of State having the power to see anonymised bid stack information. Yes, No, Unsure. Please provide further evidence in support of your views.

No. However, the intention of introducing these powers, namely to avoid budget underspend and ensure procurement is maximised, is welcomed by industry

See response to Question 12.

We believe giving the Secretary of State visibility of an anonymised bid stack would carry significant, unnecessary risks as, for offshore wind at least, it would be possible to identify individual projects from price and capacity information even if bids were ostensibly anonymised. The Secretary of State does not need full access to the bid stack to achieve the intended policy goals. The exact rationale behind this proposal is unclear and could lead to significant unintended consequences. The auction design may incentivise developers to bid strategically, which the Secretary of State might misinterpret as minimal viable bids. This could lead to incorrect assumptions about a technology's cost, potentially influencing the setting of parameters in future rounds.

One further alternative could be to introduce a “soft cap” approach alongside the capacity ambition/auction schedule. This would allow the Secretary of State to procure the marginal project that breaches the capacity ambition set ahead of the auction, without having to see the sealed bids of all participants. This approach could be applied to all pots and would create a mechanistic system with less administrative burden.

However, the introduction of a soft cap may require legislative change. UK Government should aim to minimise delay/disruption to AR7 and AR8 as much as possible. Therefore, a soft cap or the proposed visibility of the bid stack should be balanced against delivering Clean Power 2030 targets, if major legislative change is required for either option.

17. Would the Secretary of State seeing anonymised OFW bid information have a negative impact on:

a. Bidder behaviour: Yes, No, Unsure.

Yes.

If the Secretary of State were to access anonymised sealed bid information, there is a risk that bidders might inflate their bids. This could occur due to concerns about misinterpretation and the potential influence on future rounds.

b. Investor confidence in the CfD scheme: Yes, No, Unsure.

Yes.

Allowing the Secretary of State to access sealed bid prices and capacities, and thereby infer project identities, shifts the CfD away from a market-driven auction to one that could be seen to be politically motivated. Investor confidence could be impacted if there was a perception that the Secretary of State could make arbitrary decisions in response to viewing bid information. This approach raises significant questions about fairness, transparency and trust, potentially undermining the integrity of the CfD scheme. As a result, investor confidence in the scheme may be negatively impacted.

c. Consumers: Yes, No, Unsure

Yes.

As outlined in our response to part a, there is a significant risk that bidders will inflate their bid prices, increasing the cost to consumers

18. Do you believe this proposal could increase the likelihood of a preferable outcome for both industry and consumers? Yes, No, Unsure. Please provide further evidence on why this proposal may increase the likelihood of a preferable outcome for both industry and consumers.

Unsure.

In AR6 we saw a budget underspend of around £251m. If the budget was set after a review of the sealed bids, this underspend could have been avoided and at least one more high-quality project could have been procured. However, if the Secretary of State was granted access to the full bid stack then this could have unintended negative consequences.

We set out in our response to Question 12 and Question 16 what we believe would be a better approach to achieve the same objectives.

19. Do you believe any further assurances, other than those in the Contract Allocation Framework, are required? Yes, No, Unsure. Please list any further assurances which would be required.

A clear auction schedule with capacity targets for each pot for the next five auctions, linked to Clean Power 2030 targets

Alongside the auction schedule, clear written assurances that these capacities will be supported through appropriate budgets as agreed with other government departments such as HMT. Without these assurances, industry would not have confidence in the auction schedule and the approach to removing budgets will be materially undermined and lead to worse outcomes than the status quo.

20. Do you agree with the rationale to only apply the new bid stack approach to fixed-bottom offshore wind, for now: Yes, No, Unsure

Yes. However, we believe there are better ways to deliver on the policy objectives.

We agree with the rationale for applying this new approach only to fixed-bottom offshore wind in AR7. However, we recommend that this approach be considered in future allocation rounds for floating offshore wind, given that the number and size of floating offshore wind projects are set to increase significantly in the coming years.

[If 20 = "No" or "Unsure"] Please select which other technologies you think the new bid stack approach should apply to: Solar PV, Onshore Wind, Tidal, Geothermal, Wave, Floating Offshore Wind, Unsure.

N/A

Please provide any further comment on your view on the rationale to only apply the new bid stack approach to fixed-bottom offshore wind, for now.

The Government expressed a firm commitment to maximise the deployment of floating offshore wind projects in AR7, saying *"we intend to support multiple Test & Demonstration scale projects in AR7. We will look to set the budget and other round parameters to facilitate this."*

Whilst we have concerns about the proposed bid stack approach, we would support measures as discussed in response to Question 12 and Question 16 being applied to floating offshore wind in AR7 if they would help to ensure all eligible T&D projects are procured.

Contract Allocation Framework amendments

21. Do you agree with the rationale for flexible bids being closed for OFW projects? Yes, No, Unsure. Please provide further evidence on your view on flexible bids being closed for OFW projects.

No.

Flexibility in bid prices could allow bidders to offer lower capacities and slightly higher prices, which could result in a lower budget take overall when compared to not having flexible bids. This could lead to lower consumer costs overall.

Additionally, projects are still likely to be "flexible" in their approach to auction bidding without flexible bids as options such as project phasing or separate project bids for different capacities of projects are facilitated within auction rules.

Flexible bids could offer the Secretary of State a valuable mechanism to procure capacity without the risk of overspend. For instance, the Secretary of State might hesitate to approve a large project due to its substantial budget requirements. However, with flexible bids, there is an opportunity to accept a project at a slightly higher cost per unit but with a lower overall capacity, thereby reducing the total budget needed. This flexibility ensures that the Secretary of State can procure capacity more closely aligned with the Government's capacity ambitions.

Chapter 2.3 - Increasing the contract term for future CfD projects

Market failure

22. Do you expect that new renewable electricity projects operating on a 15-year CfD will be exposed to greater market price risk than was originally conceived in the EMR (2013)? Yes or No? Please explain why, providing evidence where possible.

Yes.

Since the EMR (2013), new renewable projects have become considerably more exposed to market price risk due to several factors. The most notable include the increased deployment of renewables driven by government policy without the sufficient deployment of appropriate electricity transmission and support for long-duration electricity storage. The combination of these factors will continue to suppress prices and expected revenues through increased negative price risk. This risk is dramatically exacerbated by the potential introduction of zonal pricing, which would further heighten the risks of price cannibalisation, uncompensated curtailment, and periods of negative pricing. The extent of this risk is clearly demonstrated by the wind-weighted capture prices that arise from various modelling exercises conducted as part of the Government's REMA programme. Both the LCP analysis for DESNZ and the FTI analysis for Ofgem indicate the potential for annual average capture prices for wind in high-wind resource areas (e.g., Northern Scotland) to fall below £10/MWh.

New assets entering upcoming allocation rounds will have longer operational lifecycles than current operational projects. We expect onshore wind assets to have an operational life of at least 25 years with fixed bottom offshore wind expected to be at least 30 years. This means the CfD is now barely covering half the life of assets. Meanwhile, future uncertainty over price cannibalisation, negative pricing periods, and uncertainty around the potential for zonal pricing in the wholesale market are becoming greater factors in project financing.

Zonal pricing would exacerbate risks of price cannibalisation and negative pricing periods for onshore and offshore wind in particular. Wind generation is typically developed away from large demand centres due to factors such as wind resources, land costs, network availability and network cost amongst other key factors.

The uncertainty around zonal pricing is currently a major risk for the merchant period of projects in AR7 onwards. Zonal pricing could introduce significant price risk and volume risk for projects. Price risk would occur in zones where renewables would act as the marginal plant more frequently than a national pricing system, for example in Scotland. Volume risk is increased due to the additional uncertainty that the impact of limited network capacity could have on the ability of the market to accommodate the plant's output.

23. In your view, do you have concerns about the economic viability of CfD assets once they have reached the end of their CfD term? Yes or No? Please explain why, providing evidence where possible.

Yes, there are major concerns for Northern and Scottish generators should the government progress with a move to zonal pricing without comprehensive legacy arrangements that protect these assets from price and volume risk for their economic life.

24. If yes to 22 and/or 23, where possible, please provide evidence quantifying the impact you believe this may have on CfD strike price bids (% and/or £/MWh).

Without comprehensive legacy protection, assets are likely to price additional risks into their AR7 bids, leading to inflated clearing prices across technologies.

Frontier Economics and LCP Delta have found that a move to zonal pricing could lead to £2.5-4.0 billion in additional consumer costs as a result of increased strike prices in AR7 compared to the status quo or reformed TNUoS in a national market. The report finds that average strike prices could increase from £70/MWh to £96/MWh (in 2022) prices under a move to zonal pricing.

Potential benefits

25. Do you agree that increasing the contract term will reduce cost of capital? Yes or No? If yes, please state the breakdown of impacts on i) cost of debt, ii) cost of equity, and iii) gearing. If no, please explain why, providing evidence where possible.

Yes.

There are materially different levels of risk associated with non-contract backed merchant revenues and UK Government-backed CfD revenues. Different discount rates are used to value revenues from each of these sources. The spread between the respective discount rates used is widening, as volatility in merchant markets has increased and the effects of cannibalisation are starting to be seen. If zonal pricing were to be introduced, we would expect this to widen even further (assuming that CfD projects would be insulated from zonal price risk using a zonal reference price, but merchant projects would not). Since an extension of the term of the CfD would mean that a greater portion of the projects revenues were covered, this would directly lead to a reduction in the overall WACC for the project.

26. If yes to 25, where possible, please provide evidence to quantify the impact you believe this may have on CfD strike price bids (% and/or £/MWh) via i) reduced cost of capital, ii) increased subsidy period, and iii) details of discount rates applied.

Analysis by Aurora Energy Research, commissioned by RenewableUK found that the minimum economic bid price for a 100MW offshore wind farm decreases from £58/MWh for a contract length of 15 years to £53/MWh and £50/MWh for 20 and 25 years respectively (2012 prices). This is a 9 – 14% reduction.

It is important to note that longer contract terms will reduce strike prices *all else equal*. Strike prices are determined by a range of factors many of which are beyond both government and developer's control (eg supply chain costs). This means that a longer contract term will not necessarily lead to lower strike prices relative to previous allocation rounds, depending on how these exogenous factors change over time. However, for a given set of market conditions, longer contracts will lead to lower strike prices than would otherwise be the case if a 15-year contract were maintained.

27. To what extent would a potential reduction in strike price from longer contracts be limited if there was insufficient competition in auctions? Please provide evidence where possible, specifically, detail on the justification for your assessment of the extent would be appreciated.

It is unclear why this should be any more of a concern than at present with auctions for 15-year CfDs; insufficient competition will increase strike prices in auctions both shorter and longer term CfDs but the length of the contract would not be a factor in determining the degree of the increase.

What is important here is to consider the relative benefits of extending the CfD contract length, rather than the net or absolute benefits. All things being equal a long CfD term will reduce CfD strike prices. This will be true for all projects bidding in, although given the pay as clear nature of the auction, the reduction that consumers will see will be bid price reduction of the marginal bid clearing the auction.

Other factors influencing the CfD strike price will be the level of competition and the uncertainty around the move to zonal pricing. So an assessment of the competitive tension and risk premia being applied to bids needs to be included in the counter-factual strike price of the auction against which any benefits of long CfD contracts are being measured.

28. Are there any further changes to auction rules or design that the Government could make to increase the likelihood that project cost savings feed through to strike price bids, and so billpayers, and/or offset the limitations from insufficient competition?

Increasing contract length is currently the most powerful lever at the governments disposal to reduce CfD strike prices.

Costs / unintended consequences

29. Do you agree that increasing contract term for CfD assets would increase wholesale electricity price cannibalisation? Yes or No? Please explain why, providing evidence where possible.

No.

Price cannibalisation is an inherent characteristic of a renewables-dominated electricity market. The short-run marginal cost of most renewable energy sources is close to £0/MWh. As a result, even if generators were to operate on a merchant basis, they would continue to generate electricity at most positive prices to earn wholesale market revenues, but not when prices are negative. This means that similar levels of price cannibalisation would occur during the merchant tail. It can only be mitigated through demand growth, demand flexibility, and broader power system flexibility, such as long-duration electricity storage.

Wholesale price cannibalisation happens when same type renewable generation assets produce at the same time. We do not agree that increasing the CfD tenor would increase price cannibalisation, because for both scenario that the CfD tenor is increased and counterfactual, the power system may experience relatively same level of renewable generation. This is because merchant assets usually are not incentivised to reduce their power generation during peak production periods as these assets, wind turbines, for example, are designed to operate continuously and frequent stopping and starting can cause mechanical stress on components leading to wear and tear and reduced lifetime. Based on this feature, a merchant renewable asset may continue to produce even at zero or negative prices provided that the foreseen costs outweigh that of revenue cannibalisation.

30. If yes to 29, do you consider that this could materially impact security of supply? Yes or No? Please explain why, providing evidence where possible.

No.

Longer CfD terms may increase security of supply if the change attracts more investment to the UK.

31. Do you consider that increasing the contract term would materially increase overall investor confidence in the renewable electricity industry? Yes or No? Please explain why, providing evidence where possible. Yes.

New renewable electricity projects are encountering significantly greater market price risk than previously anticipated in the EMR (2013). Extending the contract term would instil greater investor confidence in the sector by providing a higher level of protection against these price risks, which the government can manage more effectively, particularly the policy risks which are within the government's gift.

It is also important to note that 15-year CfD contracts are relatively short compared to those in other global markets, such as the 20-year contracts in Denmark, France, and Ireland and the 25-year contracts in Poland. Therefore, to attract the level of investment required to reach CP2030, the UK's policy framework for renewables must remain internationally competitive.

Extending the CfD contract term would send a powerful signal to investors, significantly boosting their confidence in GB's renewable electricity industry. Internationally, projects and investors are grappling with supply chain disruptions and high capital expenditure costs. Offshore wind projects, in particular, are facing numerous challenges, with many global investors struggling. Increasing the CfD contract term in GB would provide much-needed certainty to the investment community and financial institutions. This change would offer assurances that investments are secure and viable during a critical time, encouraging long-term investments in renewable energy projects.

If the Government were to announce a decision to introduce zonal pricing before AR7, extending the CfD contract length could help mitigate some of the risks and maintain a degree of investor confidence. However, several risks and uncertainties would remain unaddressed, likely impacting the outcome of AR7. The introduction of zonal pricing would significantly undermine investor confidence, outweighing any benefits of an extended contract length.

32. Do you consider there are any unintentional consequences that this policy change could create which have not been considered within this consultation? Yes or No? If yes, please provide evidence where possible.

Yes.

If changes for AR7 cannot be made, or are signalled instead for AR8, then there are real risks for competition and distortion. Projects may be incentivised to wait for AR8 to secure a longer contract, undermining efforts to support acceleration to Clean Power 2030 and delaying supply chain orders. Uncertainty around when changes could be made would also impact investor certainty. It is therefore essential that the government confirms that they will either implement this change or not for AR7. Deferral carries major risks of delaying Clean Power targets and reducing liquidity in this auction.

Implementation

33. Considering the factors of i) the impact on the wholesale market and security of supply, ii) the impact on CfD strike price bids and billpayers, and iii) overall investor confidence in the renewable electricity industry, in your view, what contract term best balances these factors? Please provide evidence to support your view.

The original basis for the CfD duration of 15 years was that this formed 60% of the total project lifespan of 25 years, which was typical for renewable generation projects at that time. The intention was to provide revenue stability for over half of the project lifespan while retaining a period of merchant operation. Based on this rationale, contract length should be extended to 25 years to reflect the longer lifetime of new renewable energy projects.

34. Do you consider that an alternative approach to price indexation (currently CPI) may be required in any additional years of the contract to better balance the risk between generator and consumer? Yes or No? Where possible, please set out which mechanism you believe is most appropriate and why.

No.

CPI is still the most appropriate index.

We see no compelling logic as to why years beyond the initial 15 should be treated differently. Reducing indexing in those years will simply lead to higher bids, in the same way that removing indexing entirely would. This would be an unnecessary over-complication with no net benefit.

The UK approach to indexation is seen as a gold-standard and a key reason why the UK scheme in general is viewed as a prime example of a stable and secure investment mechanism. No index correlates perfectly with the cost base of renewable energy sources. However, CPI is considered the measure of general inflation and accepted proxy for inflation.

CPI indexation throughout the lifetime of a project has key advantages, including the ability to hedge the index in the long-term and the certainty of inflation protection through the contract. This enables developers to reduce inflation risk, attract low risk cheap capital to projects and ultimately lower project costs and strike price bids. Strike prices may be unnecessarily high if developers' contingency estimates are overly risk-averse or inaccurate in forecasting changes in costs that do not materialise

35. Do you consider that increasing the contract term from 15 years should apply to all renewable technologies currently supported under the CfD? Yes or No? Please explain why, providing evidence where possible.

Yes, provided that technologies' expected life is longer than the CfD term.

36. If no to 35, what unintended consequences do you consider there may be for enabling longer contract term for i) OFW only, ii) OFW and ONW only, iii) OFW, ONW and solar only. Please provide evidence where possible.

An increased contract length enables a project to bid at a lower strike price. For this reason, all projects competing in the same pot must have the same contract length, to ensure equitable treatment under the CfD auction process
Based on the AR6 pot structure, enabling longer contracts for onshore wind and solar will clearly affect competition with the other mature technologies in Pot 1. Therefore, Scottish Renewables recommends that Pot 1 consist only of onshore wind and solar, especially given that AR7 should focus on CP2030 and the technologies necessary to deliver it.

Chapter 3.1 - Solar PV Target Commissioning Window

37. Do you agree with the Government's proposal to increase the current TCW for Solar PV from 3-months to 6-months with effect from AR7. If not, please tell us why and provide evidence to support your position.

We support an increase in the current TCW for Solar PV. However, we believe there is still a compelling case for the increase to be to 12 months, rather than 6 months, in particular for larger scale projects.

Consistency in treatment of technologies in the CfD process

There is a general principle underpinning the CfD process and conditions that technologies with similar characteristics should be treated in a similar way, particularly if they are competing in the same CfD auction pot.

As the consultation document notes, the majority of eligible CfD technologies have TCWs of 12 months. In contrast, solar PV currently has a 3 months TCW and the consultation states that this is because it has a faster build time than other technologies.

That may have been true in 2013, when the CfD was first introduced, when the great majority of solar projects were much smaller in scale than current practice. However, for the current and future larger scale solar projects, construction times are now comparable to other technologies, such as onshore wind projects.

Given this similarity, it is unreasonable to cap the TCW for solar projects at 6 months when other projects with similar construction times have 12 months available. This is because a difference in TCW duration can have a direct impact on the relative competitiveness of solar and other technologies competing in the same CfD auction pot, as solar projects will have a higher risk of erosion of the full 15 year CfD term. Distortion of the CfD auction due to differences in the auction parameters between technologies should be avoided as far as possible.

The Need for a 12 months TCW for solar projects

The consultation notes that, had a 12-month TCW been available to solar projects in AR6, developers choosing the second delivery year would have had approximately four and a half years, to commission without financial penalty. The implication is that this is longer than a solar project could reasonably require and a period of four years (with a 6 month TCW) is sufficient.

However, there are reasons why a longer period could reasonably be required. Project programmes cannot be timed to exactly match the timing of CfD contract award and the start and end dates of delivery years. Programmes are constrained by many factors, including the date a site becomes available, site specific access time restrictions, supply chain availability, contractor availability, DNO or National Grid requirements on the timing of commissioning windows and other factors outside the developer's control. Consequently, for larger solar projects, the time to commission from CfD award can exceed four years. As a result, a 6 months TCW could still result in CfD erosion.

The consultation notes that several larger solar projects have secured CfDs with a 3 month TCW and suggests that this is evidence that some larger projects can deliver within the 3 month TCW. This may be true. However, it is also possible that some larger projects have tolerated a degree of CfD erosion within the clearing strike price secured through the CfD auction. The pipeline of future solar projects has a much higher proportion of large scale projects than the pipeline up to AR6. The TCW is likely to become a much more significant impact in future auction rounds.

38. Do you have any views on any of the impacts explored in the assessment? In particular, we would welcome further evidence on:

- **a. The benefit that could be captured in the near-term (AR7 and AR8) for solar PV projects from extending the TCW, or any risks of the proposal;**
- **b. Any alternative design options that you consider might better balance the need for increased flexibility for some solar projects whilst ensuring that developers are still incentivised to build out efficiently.**

<u>Delivery of 2030 Clean Power Mission</u>

The consultation notes that, in proposing resetting the solar TCW to 6 months, the Government wishes to strike a balance between giving future solar projects a reasonable timeframe in which to commission and maximising the likelihood of them coming online in time to contribute to the delivery of the 2030 clean power mission.

We would challenge the line of reasoning in this comment. If insufficient time is provided for a project to deliver without CfD erosion with achievable programme timings, this will not result in the project accelerating delivery. As noted above, there are fundamental constraints on how quickly a large scale solar project can be delivered. What an insufficient TCW will do is worsen the project economics, increasing the risk that project doesn't proceed at all. In that case, it will make no contribution to any target for net zero delivery.

<u>Options for solar TCW duration</u>

We understand that there is a potential concern that a 12 month TCW is significantly longer than smaller solar projects require and does not incentivise early delivery towards the 2030 clean power target.

While the risk and financial impact of the 3 month TCW is less for smaller projects, this is still potentially significant, even for a 50 MW scale project or smaller. For this reason, our preference would be to have one single TCW duration of 12 m for all sizes of solar projects.

However, if there is a continuing concern over smaller solar projects, then one potential option is to specify a 12 month TCW but only for larger solar projects. A suitable threshold would 100 MW capacity, to match the updated planning threshold for solar projects to qualify as an NSIP project subject to the DCO consent process.

Chapter 3.2 - Eligibility of surrendered CfD capacity for AR7

39. Do you agree with the Government's proposal to apply a temporary restriction on CfD capacity released by generators through the permitted reduction and FIC flexibilities being entered into AR7, and the proposed drafting in the Contract Allocation Framework to achieve

this? If not, please tell us why and provide evidence to support your position. We would particularly welcome evidence from any existing CfD generators that may be adversely affected by this proposal.

We support the proposal for a temporary restriction on surrendered CfD capacity being entered into AR7 while the Government evaluates the value for money and other implications of this practice, with the aim of implementing a long-term policy from AR8 onwards.

However, we do not follow the Government's rationale set out in the consultation. The ability to re-enter permitted reduction capacity was crucial for AR4 projects that signed CfD contract prices before the major macroeconomic shocks that followed. This facility (or some alternative mechanism to accommodate unforeseen macroeconomic shocks) is likely to continue to have significant value in a market climate characterised by significant and widespread uncertainty.

We do not agree with the position: *The Government views the macroeconomic circumstances of the last few years as largely exceptional and notes that the unprecedented cost changes for projects led to several AR4 generators to surrender some of their capacity.* Recent months have highlighted how quickly macro-economic conditions can change, and, with uncertainty likely to persist, we are now arguably entering a new phase of extended geopolitical turmoil.

There are huge risks which cannot be fully priced in or mitigated. Removing the flexibility to reduce capacity could introduce the unnecessary risk of projects being exposed to major shocks which could jeopardise their economic viability post CfD contract signature.

If the Government views the recent economic shocks as largely exceptional then the risk of projects re-entering surrendered capacity at a higher price is massively reduced. In stable economic conditions it is unlikely the Administrative Strike Price (ASP) would see a significant increase between allocation rounds. Thus, it is doubtful projects would opt for re-entering capacity as the clearing price is likely to be relatively stable between auction rounds.

There is also a risk that imposing the proposed restrictions on surrendered capacity could be counterproductive to reaching 2030 targets, since (as was the case for AR4 projects) being able to re-bid for a CfD could make the difference between enabling projects to reach reach FID in time to deliver for 2030 or not.

40. Do you agree with the confirmation and documentary evidence that applicants will have to provide to demonstrate that their applications do not contain any capacity which was previously subject to a CfD awarded in Allocation Rounds 1-6? If not, please tell us why and provide evidence to support your position.

Yes.

41. Do you have any views on any impacts explored in the assessment? In particular, we would welcome further evidence on:
a. The assessment of benefits and risks identified in this assessment, including any additional evidence on the likelihood and significance of benefits and risks identified;

b. Whether there are further benefits or risks to this proposal which are not explored in this assessment.

See response to Question 39.

Chapter 4.1 - Repowering of onshore wind

42. Do you agree with the proposed changes to the Contract Allocation Framework proposed above? If you disagree, please tell us why and support your answer with evidence.

Scottish Renewables has concerns about the 'end of operating life' requirement as it fails to consider the shorter design life of first-generation onshore wind technologies, which were consented with lease expiry dates reflecting this shorter operational life. The requirement also overlooks phased/extension wind farms that share the same expiry dates despite having different operational start dates while having the same point of connection.

This approach will force numerous onshore wind farms to be decommissioned and the site remain unused for years, contradicting the repowering policy's intent and the Clean Power 2030 Action Plan's ambitions.

To prevent wind farm sites sitting idle and expand the pool of eligible projects for upcoming allocation rounds, the Government should reduce the 'end of operating life' requirement from 25 to 20 years. Alternatively, more flexibility should at least be applied to phased/extension projects - maintaining the 25-year requirement for initial phases while reducing it to 20 years for extensions on the same site. This would enable developers to optimise sites earlier, supporting the delivery of CP2030 goals.

43. Do you agree with the documentary evidence and eligibility checks proposed above? If you disagree, and/or wish to suggest alternative evidence/checks, please tell us why and support your answer with evidence.

We largely agree.

However, we believe that for existing stations receiving support under the Renewable Obligation (RO), the RO commissioning date specified in the RO register is more appropriate than the proposed RO accreditation date.

There are instances where there is a significant lag between the RO commissioning date and the RO accreditation date. The RO commissioning date more accurately reflects the station’s operating life. According to the RO guidance for generators, the commissioning date is when the station completes tests and procedures to demonstrate its capability for commercial operation.

Evidence supporting the RO commissioning date includes witness test certificates, independent written confirmations, signed statements from the installer or manufacturer, and half hourly (HH) meter readings. Therefore, we consider the RO commissioning date to be a more accurate and reliable indicator of the start of the operating life.

44. Do you agree with the definitions to be added to the Contract Allocation Framework proposed above and in the CfD Agreement and Standard Terms and Conditions published alongside this consultation? If you disagree, please tell us why and support your answer with evidence.

The proposed definition of decommissioned generating assets covers not just the turbines but the foundations, transformers and switchgear. It is not clear why foundations, switchgear or transformers should be included in the requirement to be removed from site. It may be impossible to re-use switchgear or transformers, but excluding the possibility seems both unnecessary and inconsistent with sustainability policies. Additionally, the definition is broad enough as to cause uncertainty as to whether the obligation to decommission has been complied with – there does not seem to be any reason to define decommissioning beyond terms relating to turbine towers, blades and nacelles. The proposals also envisage the "dismantling and removal" of the existing turbines before the new turbines become operational. This will not always be the most efficient approach to completing a repowering project.

In the case of foundations specifically, they are not always refurbished or removed. The existing foundations are generally too small to support the latest larger turbine models typically deployed in repowering scenarios. As a result, the new repowering turbines, associated foundations, and infrastructure will be located in different locations. This is primarily due to the need for greater rotor diameter spacing to avoid stress on these larger turbines and to maximise their performance

Removing old foundations in this case is both costly and environmentally challenging. Therefore, typical repowering decommissioning plans, approved by the relevant decision-making authorities and statutory consultees, will refer to their retention in situ, cutting them out to approximately 1 metre below the surface, backfilling with topsoil generated from construction activities elsewhere on the site, and reseeding where appropriate. This method is the most efficient and sustainable for decommissioning existing foundations.

45. Do you agree that applicants should be required to demonstrate at the point of application that the existing onshore wind station for which they are seeking CfD support will, or would have but for decommissioning, have reached the end of its operating life by the Target Commissioning Date? If you disagree, and/or wish to suggest an alternative cut-off point, please tell us why and support your answer with evidence.

We have significant concerns regarding the application of the 25-year operating life criterion to repowering projects that were initially commissioned in phases. These sites typically represent some of the largest repowering projects with the greatest increase in capacity. They are particularly complex, requiring the coordination of various factors – land rights, grid connection dates, planning consents, and construction schedules.

Combining multi-phase sites during repowering offers several benefits:

- **Project Efficiencies**: Achieving economies of scale by combining efforts, streamlining processes, and leveraging synergies to reduce costs and complexity.
- **Site Optimisation**: Improved geographical layout and the use of larger, more efficient turbines that enhance output and land use.
- **Smoother Transition**: A back-to-back phased approach will ensure continuous energy production and minimal disruption for National Grid.

It is unclear how the operating life will be defined for repowering sites comprising multiple initial sites with different commissioning dates. If the operating life is evidenced based on the commercial operation date of the later site, it could result in significant delays to the repowering process or prevent the site from being combined during repowering and losing the outlined benefits.

If repowering is delayed, it could leave parts of the site dormant as they would have to wait beyond the 25-year operating life and may not be commercially viable to run. This would result in lost renewable capacity and delay progress towards the Government's decarbonisation ambitions.

We believe that the Government should consider this issue further and implement flexibility for multi-phase repowering sites in terms of this criterion. We understand that a backstop may be needed to prevent significantly younger sites repowering too early. Therefore, we propose that in the case of multi-phase repowering sites, the later site must have reached a 25-year operating life (as already defined), while the younger site must have reached at least a 20-year operating life, by the TCD specified in the application. This approach will ensure efficient and timely repowering of large multi-phase projects, preventing needless delays.

46. Do you agree to allowing a more flexible approach to demonstrating that the existing generating station has reached the end of its operating life through fulfilment of an Operational Condition Precedent?

We disagree with the Operational Conditions Precedent (OCP) requirement that mandates generators to declare that the existing generating station has reached the 'end of operating life' or would have, had it not been decommissioned. This requirement undermines the flexibility provided by the Target Commissioning Window (TCW) in the contract, which is essential to accommodate the practical realities of construction and the potential for projects to be completed before their TCD.

Additionally, this requirement conflicts with the recently introduced Unilateral Commercial Operation Notice (UCON). The UCON was designed to prevent generators from delaying the completion of their OCPs and, consequently, the CfD Start Date, to generate on a merchant basis. The Low Carbon Contracts Company (LCCC) can issue a UCON notice to generators if they determine that commercial operations have commenced, regardless of whether OCPs have been fulfilled.

However, the proposed operating life OCP requirement hinders generators from completing their OCPs, even if the project is commissioned and they are ready to start their CfD. In this scenario, it is unclear whether LCCC will issue a UCON, making the new OCP requirement redundant, or whether generators can use this new OCP requirement to delay the CfD Start Date for commercial gain.

We therefore believe that this requirement should not be implemented and that the full flexibility of commissioning within the TCW should be maintained.

47. Do you agree with the proposed contract changes outlined above and shown as tracked changes in the CfD Agreement and Standard Terms and Conditions published alongside this consultation? If you disagree with any of the proposed changes, or have alternative suggestions, please tell us why and provide evidence to support your position.

N/A

48. Do you agree with the Government's proposed amendments to ensure the separation between the CfD facility and the existing decommissioning plant as outlined above? If not, please tell us why and provide evidence to support your position

N/A

Chapter 4.2 - Phased CfDs for floating offshore wind

49. Do you agree with the proposed amendments to the phased CfD contract terms to implement fully the Government's policy to extend phasing to Floating Offshore Wind? If not, please tell us why and provide evidence to support your position.

We agree with the proposal to extend phasing to floating offshore wind. Phasing has already proven to be a vital mechanism for managing the construction schedule for larger offshore wind projects and has been widely adopted. Phasing presents the opportunity for projects to begin commercial generation earlier, whilst continuing to maintain a realistic and commercially viable construction programme for the project as a whole.

However, we believe the maximum capacity for phasing should be increased above 1500MW for both fixed bottom and floating offshore wind.

Scottish Renewables would encourage increasing the 1500MW cap in recognition of the increased scale of projects in the pipeline. We believe 3000-4000MW would better reflect the future pipeline of projects that will use significant larger turbines than the typical project when the 1500MW cap was introduced. We believe this should be applied to both floating and fixed bottom projects.

The present 1.5GW cap is entirely arbitrary and was introduced at a time when turbines were significantly smaller. Larger turbines have allowed projects to substantially increase in scale whilst continuing to be developed and operated as a single, integral project. For example, when Hornsea Project One received an FID-enabling contract in 2014, it utilised 174 x 7MW state of the art turbines at its 1200 MW site. However, 10 years on with turbine technology further developed, developers are typically looking at turbine sizes of between 15MW to 20MW, meaning a similarly sized project in terms of number of turbines would be between 2.5 to 3GW in capacity.

Table 1: Selection of Projects Exceeding 1,500MW Capacity

Developer	Project	Leasing Round	Capacity (MW)
Fixed Bottom			
SSE Renewables	Berwick Bank		4,100
BP & EnBW	Morven	ScotWind	2,907
Ocean Winds	Caledonia	ScotWind	2,000
RIDG, Corio & TotalEnergies	West of Orkney Wind	ScotWind	2,000
ScottishPower Renewables	Machair Wind	ScotWind	2,000
Sub-total			*13,007*
Floating			
Mainstream RP & Ocean Winds	Arven	ScotWind	2,300
ScottishPower Renewables & Shell	Campion Wind	ScotWind	2,000
ScottishPower Renewables & Shell	Marram Wind	ScotWind	3,000
SSE Renewables & COP	Ossian	ScotWind	3,610
Sub-total			*10,410*
Total (MW)			**23,917**

However, Scottish Renewables questions why the Required Installed Capacity (RIC) is set at 95% of the Initial Capacity Estimate, compared to 85% for fixed bottom projects. Given the novel nature of the technology and the fact that construction is more seasonally constrained than fixed bottom (i.e. towing fully assembled floaters and on-site hook-up), we strongly recommend that floating offshore wind's RIC be set at a minimum of 85%, if not lower. We also recommend increasing the Longstop Period from 12 to 24 months.

We would also ask that Government considers phasing policy for onshore wind generators of a certain size. As technological advancements lead to larger turbines, we anticipate the emergence of significantly larger onshore wind sites. These sites will necessitate a phased approach to minimise construction risks.

Phasing will be particularly important for repowering projects that deploy a back-to-back phased approach for decommissioning and commissioning. Such an approach involves decommissioning existing infrastructure while simultaneously commissioning new installations. By adopting CfD phasing for onshore wind, the Government can facilitate a smoother transition, minimise downtime, and significantly enhance the overall efficiency and cost-effectiveness of onshore wind construction.

Chapter 5.1 - Changes relating to implementation of Part 5 of the Energy Act 2023 (establishment of NESO)

50. Please flag any unintended consequence of these changes that Government may need to consider, and let us know if you think any other changes ought to be considered as a result of the establishment of NESO.

Scottish Renewables has not identified any potential unintended consequences of these proposals.

Chapter 5.2 - Changes relating to Clean Industry Bonus payment suspensions

51. Do you agree that the amendment to the conditions relating to CfD payment suspensions is sufficiently clear and fit for purpose? If not, please state your reasons and an alternative proposal.

We agree.

Chapter 6.1 - Changes to regulations relating to the Clean Industry Bonus

52. Please flag any unintended consequence of this change that Government may need to consider.

Scottish Renewables has not identified any potential unintended consequences of these proposals.

Chapter 6.2 - Wider Risks that may impact the Allocation Round

53. Are there exogenous issues not covered elsewhere in this consultation that you are particularly concerned about when it comes to Allocation Round 7?

REMA: The potential announcement of a move to zonal pricing poses the single greatest risk to the success of AR7 as considerable detail of future market arrangements will still be unknown at time of bidding and grandfathering proposals announced to date do not comprehensively mitigate additional risk. This could mean that risk premiums that result in £billions of additional consumer costs are added to bid prices, or simply that projects opt not to participate in AR7 meaning it fails to deliver the capacity required for Clean Power 2030. The single most impactful action the UK Government could take to ensure the success of AR7 and future allocation rounds necessary for delivering Clean Power 2030 is to rule out zonal pricing without delay and commit to an evolutionary programme of reform.

TNUoS: If ongoing reforms – CMP444 (cap and floor), CMP432 (onshore security factors) – fail to deliver meaningful protection and/or REMA reforms fail to maintain this protection then northern projects needed for Clean Power 2030 will not have business cases which supports bidding into AR7.

Additional delivery years: DENSZ should introduce additional, later delivery years for all technologies as part of the AR7 auction design due to challenges developers across the sector are facing with the delivery of projects. DESNZ should engage closely with developers on this issue ahead of finalising AR7 auction parameters.

Connection delays: Given the scale of enabling works needed to deliver CP2030, the risk profile for delays has never been higher. A lack of grid delay protections could impact appetite to participate in AR7. All avenues of addressing this issue should be reviewed.

Grid connections: Connections Reform is still underway, and revised connection agreements will not be issued until later this year. This has the potential to impact AR7 – impacts which will be exacerbated should delivery years not be extended. DESNZ should ensure NESO provides new connection dates to projects well in advance of the application window opening.

Scottish Renewables has commented at length on outstanding uncertainties within Connections Reform, including through its recent response to Ofgem's minded to position, which are at considerable risk of jeopardising the success of upcoming Allocation Rounds.

Some of our key concerns are:

- Misalignment between the existing pipeline of onshore wind and solar projects and the allocated capacities across the UK within the CP30 Action Plan. Based on flawed assumptions, advanced projects in Scotland that have made considerable time and financial investment will be effectively halted in favour of unrealistic ambitions for projects in England and Wales.

- Lack of appropriate protection under NESO's 'Protections' for projects in the Section 36 planning process that submitted planning before December 20, 2024, but may not receive consent by the implementation of Connections Reform, CMP435. As above, such developed projects, of which there are ~4GW of onshore wind in Scotland, would be at risk through the current reform design.

Ofgem must be urged to address these errors to avoid a wealth of viable projects losing firm grid connections, and thus, the ability to bid into AR7 and AR8.

Timing: Particularly in the case of joint ventures which have more protracted approvals processes, there may be insufficient time between a decision on REMA and wider market reforms being announced and the application window closing for projects to gain approval to submit a bid in AR7. To avoid unnecessary delay to AR7, we therefore propose that projects which have applied be able to withdraw from the auction process prior to the sealed bit window opening without penalty go give projects more time to understand policy announcements before committing to participating in AR7.

END