Emailed to: ContractsforDifference@energysecurity.gov.uk

March 11, 2024

To whom it may concern,

Consultation Response: Consultation on proposed amendments for Allocation Round 7 and future rounds of the CfD

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.

We are grateful for the opportunity to respond to this consultation on proposed amendments for Allocation Round 7 (AR7) and considerations for future rounds of the Contracts for Difference (CfD) scheme, and we provide detailed answers to the consultation questions in the attached annex.

We summarise our response in the points below:

- **Repowering:** Scottish Renewables agrees that only projects that are subject to full repowering should be eligible for a CfD and we agree that full repowering of onshore wind sites should be eligible for AR7. However, we believe there is likely to be a case for specifying an end of operating life threshold shorter than 25 years for earlier renewable generators given the shorter lifespans of these early projects. We also do not believe that projects should be required to at least retain their capacity. We agree that forward bidding will be required to enable repowering via the CfD.
- **Appeals:** Scottish Renewables' preferred proposal for delivering increased certainty of delivery timelines for applicants is 'Option 1 – publish a fixed timetable'. We do not believe 'Option 2 – changing grounds for appeal' should be carried forward as this option

would mean it is less likely that a developer is able to participate in a CfD auction. We also believe that there are significant drawbacks associated with ‘Option 3 – introduce a pre-qualification process’ including additional complexity, limited benefits of a shortened auction timetable, and an earlier deadline in the annual auction cycle.

- **Phased CfDs for floating offshore wind:** Scottish Renewables supports extending phasing policy to floating offshore wind to enable the delivery of larger-scale projects. We believe that the existing the requirement to build within one lease area for fixed-bottom offshore wind is appropriate for floating offshore wind project phasing. However, the 1500MW cap on overall capacity is no longer appropriate and should be lifted for both fixed and floating projects. We also believe that the government should urgently consider extending the Delivery Years for floating offshore wind and fixed bottom offshore wind to allow projects to better manage supply chain constraints and the risk of grid connection delays.
- **Co-located generation and hybrid metering:** Scottish Renewables agrees that introducing hybrid metering would support innovation and more flexible use of CfD-supported renewable generation. Offshore wind will require special consideration to remove barriers to co-location as current arrangements mean it is only possible to co-locate other technologies at the offshore substation which is currently economically unfeasible. The simplest solution to this problem would be to relocate the BMU boundary metering to the onshore substation.
- **Supporting innovation in floating offshore foundation technology:** Scottish Renewables is concerned that the proposals to open Pot 2 to emerging non-floating technologies could divert support away from the deployment of floating offshore wind. This would mark a significant change in policy direction which could undermine investment in projects and the supply chain and ultimately mean that cost reductions and resulting consumer benefits are not realised. However, we realise that there are other innovative technologies which could prove cost-effective which currently do not have a viable route to market. Whilst the majority of Scottish Renewables’ members support maintaining dedicated support for floating offshore wind, there is not a consensus view across membership about how best to address the challenge of defining different offshore wind technologies within the CfD framework.
- **Supporting improved coordination of offshore transmission infrastructure:** Scottish Renewables agrees that no change to regulations is required to support eligibility of bootstrap-connected projects for the CfD scheme. For offshore wind farms connected to multi-purpose interconnectors (OWF-MPI), we agree with DESNZ’s assessment of the interactions between the CfD and the Home Market (HM) and Offshore Bidding Zone

(OBZ) models. However, we believe that further work needs to be done to fully establish the potential role of the CfD in the OBZ model. We support the proposal of a ‘flexible CfD’ and recommend that DENSZ explores further options for accommodating OWF-MPI projects in the CfD, such as extending contract terms. Depending on factors such as regulatory arrangements, trading arrangements and the market in which an OWF-MPI is operating, these projects could deliver significant savings to consumers. We therefore would welcome an in-depth analysis of the potential impact of OWF-MPI projects.

- **Indexation:** In principle, Scottish Renewables agrees that a change to the inflation-indexation of CfDs could help to protect projects against future macroeconomic shocks. In practice, we believe a bespoke commodity-weighted index could likely offer the greatest improvement on current arrangements. The use of CPI for inflation-indexation has several advantages over PPI including being relatively stable and easier to hedge. We therefore do not recommend that PPI is considered further for use in inflation-indexation.

Scottish Renewables would be keen to engage further with this agenda and would be happy to discuss our response in more detail.

Yours sincerely,

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Annex: Responses to Consultation Questions

Section 1 – Proposals for Allocation Round 7

Repowering

1. Do you agree that the eligibility criteria for full repowering appropriately balances CfD policy objectives of supporting decarbonisation, ensuring security of supply, and minimising costs to consumer?

We agree that, for existing renewable generators, only those that are subject to full repowering should be eligible for a CfD.

However, CfD contracts for existing projects should not only be offered for full repowering at the end of the operational life. Since these projects were commissioned, Government's ambitions for renewables has significantly increased. Whilst we fully support Government's increased ambitions, as the consultation recognises this does mean that there is potential for a significant drop in future wholesale prices particularly for wind. This issue is faced by any project at the end of its support. This means that projects at the end of their support run the risk that low wholesale electricity prices do not cover their operational costs, particularly if located in an area with high transmission network charges. Entering into such contracts for existing projects would also have the benefit that if prices are high, as have been seen recently, consumers would be protected from those high prices through the CfD payback mechanism.

2. Do you agree that use of the power generation cost assumptions to define end of operating life is an appropriate metric to capture those projects which will be seeking to fully repower in each allocation round?

It is important that there is a clear definition of end of operating life for existing renewable generators. The principles and methodology that form the basis for determining end of life should be the same for all technologies. We welcome the two broad principles set out in the consultation.

The proposal to define ‘end of operating life’ in line with operating life assumptions drawn from the published 2023 DESNZ Electricity Generation Costs Report would be a “no regrets” option, that ensures there is no possibility of incentivising early closure of operationally and commercially viable projects.

However, a potential drawback of this approach is that projects that become genuinely unviable at an earlier time will be decommissioned and then need to wait until the site become eligible for CfD support before repowering. An example would be a project reaching the end of the 20 years of support from the Renewable Obligation (RO) that is not commercially viable on a merchant basis.

Although a generator will have an operational life specified at the time of commissioning, in practice as the end-of-life approaches, the operator will regularly review the commercial viability of the generator, as maintenance costs in particular can significantly increase towards the end of life. If projected costs exceed projected revenues, then the operator is likely to take the decision to decommission the generator, irrespective of whether the expected target operational life has been reached.

Also, many of the earliest projects for each technology (which are those now approaching decommissioning) had shorter intended operational lives than the more recent projects forming the basis of the Generation Costs report. For example, early onshore wind farms assumed an operational life of 20 years, rather than 25 years, so maintenance costs could start to increase well before 25 years is reached. In addition, earlier renewable generation technologies were less efficient than more recent technology, so revenues are likely to be lower than for generators commissioned now.

These factors mean that a number of the earliest projects could decommission some years before reaching 25 years’ operating life. If the CfD is not accessible for fully repowering until the 25 years period is completed, then the site will remain inoperative in the meantime, with the 5 year gap being a lost opportunity for renewable generation.

Another factor is that most of the earliest renewable generation projects were supported by the Non-Fossil Fuel Obligation initially, with subsequent projects supported by the Renewables Obligation (RO). The duration of RO support was for 20 years. If, when the RO support ends, a further 5 years must elapse before the site can access the CfD by full repowering, then the existing generator will need to operate on a merchant basis to continue. If the revenues from this are not sufficiently certain to cover maintenance and operating costs, then the existing generator may simply be decommissioned at the end of the RO, again with 5 year gap in generation.

Although a gap in generation at a single site would not be a significant concern, if this happens at a large proportion of the sites reaching end of life, then the total loss of generation could be significant.

We recommend a detailed review is carried out to confirm the likely commercial operating life of the earlier renewable generators in practice. This will establish whether a significant gap could arise and whether there is a case to consider shortening the period for “end of operating life” for onshore wind farms from 25 years to (for example) 20 years.

If a shorter end of operating life threshold is specified, this could require additional conditions, to minimise the risk that the availability of a repowered CfD distorts commercial decision making. The review should consider this as well. Should a case be established, one option might be to introduce a shorter period for AR7 but keep the definition of “end of operating life” under review to ensure it remains valid going forward.

We also believe that it would be difficult to apply a practical rule to assess whether CapEx costs for a repowering project were similar to a new build. We recommend that DESNZ consider the workability of this eligibility criterium further in partnership with industry.

3. Do you consider that each project should need to at least retain capacity, or do you foresee any challenges with this assumption?

We think that a requirement to at least retain the capacity of the previous generator on a site is an unnecessary restriction which could prevent some sites from repowering. We appreciate that policy needs to maximise value for the consumer while avoiding barriers to viable repowering projects that boost renewable output and cut emissions. Indeed, most repowering projects will likely aim for retaining or increasing capacity as larger windfarms typically have a lower LCOE. However, viable projects that have reduced capacity for reasons outside their control should not be automatically precluded from CfDs.

Full repowering, particularly of the earliest developments, is very likely to use a smaller number of turbines, each of greater capacity, compared to the original development. Whether this is less than, equal to or greater than the capacity of the original development will depend on the full set of site-specific circumstances and any of these outcomes is possible.

For example, local environmental conditions may have changed since the original development was built, creating a new constraint that reduces the scale of development that is feasible. Local network conditions can also change, affecting the capacity that can be connected. Additionally, large onshore sites may be phased to reduce construction risk. Developers may also have plans to co-locate at a site which would reduce repowering capacity.

Conversely, it is quite possible is that a new site design with larger turbines has a greater total capacity than the original, despite having fewer turbines. Applying a rigid rule to repowered site capacity will not accommodate the full range of possible outcomes.

What will be consistent across every site is that a developer will always seek to maximise the commercially viable capacity at the development site, subject to planning, environmental and other constraints. If a repowered project does not retain capacity, it will almost certainly be due to one or more constraints preventing this.

However, that reduced capacity does not mean that the site should not be fully repowered, because otherwise a potential renewable resource will be lost for future use. There is a large, but nonetheless finite, number of sites that are suitable for renewable generation and losing sites due to such an arbitrary rule would make the delivery of net zero targets incrementally more difficult and potentially more costly to the consumer.

4. Do you agree full repowering of onshore wind sites meets each of the repowering eligibility criteria and should therefore be eligible for AR7? What evidence do you have to support this?

Yes, we agree that full repowering of onshore wind sites meets each of the repowering eligibility criteria and should therefore be eligible for AR7, with the exception of retaining current capacity and the assumption of a 25-year operating life (see our answer to Q.3. and Q.4.). The policy should enable repowering of all available projects as the operating life varies between them.

Our view is that full repowering of an onshore wind site, particularly first-generation sites, will be similar in cost to that of commissioning a new build and will require similarly high upfront costs. Repowered projects are in many respects similar to green field, new build projects – developers will likely seek to install the latest and most efficient turbines suitable for the site in question. In addition, the net cost of decommissioning of repowering will most likely add to the total cost. So, the option of a CfD support seems equally applicable.

We support the minded-to decision to enable only onshore wind for full repowering via the CfD in AR7 in the instances where projects meet the repowering criteria.

In addition, we would like DESNZ to give clarity on how other criteria which is applicable for new build projects will be applied on repowering plants such as Grid Connection, Planning permissions, other conditions precedent, etc.

Also, we would like to highlight that in some cases, repowering can be more complicated than a new build project because while it is on the same site, the layout or civil infrastructure may get changed and hence the commissioning timelines could be longer than a new build project. Hence, we recommend that the UK Government should assess the case for providing flexibility in extending the delivery years for such projects.

5. Do you agree that all other technologies do not meet the eligibility criteria for AR7? If not, why not and what evidence do you have to support this position? We are particularly interested in any costs data and definitions you may be able to provide on the full repowering of respective technologies.

We agree that all other technologies do not currently meet the eligibility criteria for AR7. However, the eligibility of repowering projects for other technologies should be kept under regular review for future allocation rounds.

In particular, we agree with the comment in the consultation, that it is not clear from existing evidence that full repowering of landfill gas would require high upfront capital costs equivalent to that of a new build, or that full repowering would be an efficient and desirable approach for landfill sites developers or an efficient outcome for consumers. Unless and until a compelling case for including landfill sites in full repowering can be made, they should not be included.

6. Is enabling forward bidding for repowered projects required to better enable repowering via the CfD? What impact would enabling forward bidding have on reducing non-generation periods between decommissioning and recommissioning of the site?

Yes, in our view forward bidding will better enable repowering via the CfD.

As a guiding principle, minimising the interval between the end of operation of the existing generator and commissioning of a new fully repowered generator will maximise the total low carbon output of the site, in turn maximising the contribution to the delivery of net zero.

To minimise this interval time, the operator will need to start planning for full repowering several years before the end of operational life (or the end of a support scheme, if sooner) and to start making financial commitments (e.g. placing orders for equipment with long lead times) before the existing generator has ceased operating.

To enable the operator to make such early financial commitments, it will be essential to allow forward bidding for a CfD and to secure a CfD before the existing generator has ceased operation.

Appeals

7. What are your views on the three options outlined? Is there one option in particular which, in your view, would be the most suitable to take forward in helping to deliver an increased certainty of delivery timelines for applicants?

SR’s preference is for Option 1 - Publish a fixed timetable.

We don’t consider that it is appropriate to pursue “Option 2 – Changing grounds for appeal”. The reason is that the priority for a developer is to ensure that they compete in an auction round and this option would make that less likely. Clerical errors also do not necessarily only happen on the part of developers, so any changes to the appeals process should not limit developers’ ability to challenge improper decisions.

We agree that “Option 3 - Introduce a pre-qualification process” could potentially reduce the duration and uncertainty of the existing auction timetable. However, it is not clear how this would be achieved in practice as it is not clear from the consultation if the auction result will be published two months after the close of pre-application window or the close of sealed bid window. Since the prequalification window will be followed by the prequalification assessment, Tier 1 and 2 appeals process, sealed bid window and allocation process, which cannot be completed in two months' time, this implies that the consultation is referring to auction result being published two months after the sealed bid window. However, this will potentially lead to a longer auction timeline than in the current process and hence defeat the whole purpose of bringing the auction forward to December and having a prequalification window.

In any case, we believe there would be limited benefits in terms of shortening the auction timetable in an annual cycle. Option 3 has the major disadvantage, from a developer's perspective, of bringing forward the deadline in the annual auction cycle to a significantly earlier time. This increases the probability that any project facing a delay in securing planning consent or a grid connection offer (both necessary to qualify for the auction) will not receive these in time for the application window and will miss that auction round entirely. Alternately, if projects are prequalified without planning/grid consent and approved "with conditions", then as per the consultation proposal applicants may not be able to change their capacity which they entered at prequalification. This can be challenging because applicants may have to reduce their capacity if they can't secure grid connection or planning consent for the entire or a part of the project. If flexibility is provided and projects are allowed to change their capacity at a later stage, the budget may then have to be revised which will defeat the whole purpose of Option 3. Developers will give priority to ensuring that they qualify to compete in an auction round, rather than to shortening the duration of the auction round. A shorter duration is irrelevant if the project does not qualify in time for the round.

Another drawback of Option 3 is that it adds another stage in the auction process, adding further complexity and potentially lengthening the overall process.

Furthermore, we anticipate that in option 3, because of an appeals process (similar to Capacity Market auction), it may still result in multiple scenarios and hence the uncertainty on the date when auction results are published will remain.

We believe there is scope to improve the application process to avoid the risk of non-material administrative or clerical errors, by improving guidance and simplifying forms. Despite close scrutiny when preparing applications, it is challenging to avoid minor errors.

8. If we were to follow Option 2, i.e. changing the grounds for appeal, what kind of reasons for an appeal should be ruled out? Would there be any unintended consequences in taking this approach e.g. by removing the right to appeal due to clerical errors?

We don't consider that it is appropriate to pursue "Option 2 – Changing grounds for appeal", as the priority for a developer is to ensure that they compete in an auction round and this option would make that less likely.

9. If an appeals process happens ahead of the allocation round formally opening, as with Option 3, should projects be able to be approved with conditions, provided they are met before the formal application window closes? If yes, what conditions might be appropriate?

Yes, allowing projects to be approved with conditions would give more flexibility and enable more projects to proceed and participate in each auction round.

However, we believe there is significant risk associated with this option. If qualification was offered on a conditional basis, it would increase the risk for applicants by removing their ability to appeal later in the process if there was a change in planning consent or grid connection offer, or if a clerical error was made after pre-qualification.

10. If an appeals process happens ahead of the allocation round formally opening, as with Option 3, should we require developers to agree that they will not change the capacity of their main bid post submitting their application, to increase certainty when setting auction budgets?

For Option 3 to work effectively, developers would have to agree that they would not change the capacity of their main bid post submitting their application. Applications would need to be finalised at the point of submission, including capacity, otherwise, the further amendments and checks are likely to require additional time, reducing the benefit of the early application in the first place.

However, it should be noted that this would remove vital flexibility for developers and potentially reduce the budget and capacity available to other projects. There is also risk of changes in planning consents or grid offers meaning developers are unable to bid their pre-qualification capacity. Developers may therefore underestimate their capacity to avoid this eventuality. We, therefore, believe that Option 1 provides the best solution to giving greater certainty over delivery timelines.

11. If we were to change the application and appeals window for AR7, or later allocation rounds, are there any transitional impacts that we need to be aware of?

Projects are already preparing for AR7 on the assumption that the current annual cycle and timings will apply. If there is to be any change, this needs to be notified as soon as possible.

12. Are there times in the year where you would prefer not to have the auction results released (which in turn may trigger contractual and milestone processes)?

Apart from major seasonal events, like the Christmas break, there are no times of the year to avoid when releasing auction results. If the timetable is clearly specified in advance, developers will be able to plan for any time of year.

However, it is worth noting that for AR4, which saw contracts signed in July-22, MDD fell in January which is not ideal due to the proximity to the Christmas break and the practical challenges that entails for the internal administration of all parties. If there is no change to the MDD being 18 months after contract signature, then the process could be structured to avoid auction results being released and contracts signed in June-August as this would coincide with summer leave periods where organisations have reduced capacity.

Phased CfDs for floating offshore wind

13. The Government welcome views on whether CfD phasing policy should be extended to floating offshore wind.

We believe that CfD phasing policy should be extended to floating offshore wind. This will provide flexibility in the delivery of larger-scale projects, which can reduce costs. Project phases are still developed as a single project and are a way of mitigating long construction and commissioning timelines for large projects. Procurement is typically undertaken for a single project across all phases to take advantage of economies of scale and Final Investment Decision (FID) is taken for the project as a whole, locking in prices for all phases. Therefore, there is no reduction in costs between the phases.

14. The Government welcomes views on the potential impact of extending phasing, or not, to floating offshore wind projects.

Phasing will provide flexibility in the delivery of larger-scale projects, which can reduce costs. When procuring for a project and reaching FID, costs will still be locked in for all phases of the project at the same time, so there will not be an increased cost to the consumer from allowing phasing.

If phasing is not extended, then larger floating offshore projects will have to wait until the full capacity is completed before reaching operational status under the CfD and receiving payments through the CfD. This will delay revenues from the portion of the project that is completed first, increasing the financing cost of the project. Phasing can enable earlier revenues and reduce the project cost, in turn reducing cost to the consumer through lower CfD bids.

The establishment of an enduring local supply chain with the necessary port capacity to realise gigawatt-scale floating offshore projects is reliant on investment and order commitments from developers. Introducing phasing allows developers to contract larger capacity projects at one time, directly supporting the supply chain's ability to invest in the necessary facilities. The UK supply chain for floating offshore wind needs a consistent and steady pipeline of work, which would be directly supported through introduction of phased CfD for floating projects.

We would like to outline further that the same rationale, which was applied when phasing was introduced for fixed offshore wind projects in the CfD scheme and before that for Renewable Obligation Scheme, given below, also applies for floating offshore wind projects in the current scenario:

1. Offshore wind stations are often constructed over several years due to the scale of the projects and the challenges faced with operating in the marine environment. The

UK offshore wind industry also face an additional challenge with an underdeveloped supply chain that can add to overall project build time.[1]

2. In our view, the challenges faced in construction of large offshore wind farms, such as issues with seasonality and long construction periods, are quite particular to that technology. Whilst other projects may have long project lead in times, they are less likely to be generating significant amounts of electricity on an ongoing basis before the whole project is completed. We are, therefore, not convinced at this time that there is a strong case for bringing in phased support for technologies other than offshore wind. However, given the expected increase in the size of onshore wind developments and of wave and tidal, we will keep this decision under review.[2]
3. Government recognises that large offshore wind projects are likely to be built in a series of stages. Under the Renewables Obligation regime Government already allows offshore wind projects to structure their projects in a way that recognises that they deploy over several years. The CfD allocation methodology also needs to ensure that such projects can secure support.[3]

15. If extending phasing to floating offshore wind, the Government welcomes views on whether the existing rules for fixed-bottom offshore wind project phasing, including the 1500 MW cap, are appropriate for the technology, and if not, why?

We believe that the existing the requirement to build within one lease area for fixed-bottom offshore wind project phasing is appropriate for floating offshore wind.

However, the 1500MW cap is no longer appropriate and should be lifted for both floating and fixed bottom offshore wind projects as an immediate priority. Projects applying in AR7 and future rounds will be significantly larger than the vast majority of those coming forward under previous leasing rounds, including the most recent extension projects. Table 1 demonstrates than none of the projects being developed at the time the 1500MW cap was set would have been eligible for phasing had they been developed with modern turbines. Table 2 lists projects over 1500MW that are currently in development and illustrates the volume of capacity that

[1] Statutory Consultation on the ROO 2011 & Consultation on changes to REGOs
[2] Government Response to the Statutory Consultation on the Renewables Obligation Order 2011
[3] Electricity Market Reform: Contract for Difference - Allocation Methodology for Renewable Generation

would not be eligible for phasing should the 1500MW cap not be lifted. We therefore believe a cap of 3000-4000MW would suitably reflect the significant technological advancement and growth in the size of projects since the 1500MW cap was set. To accommodate larger-scale projects, like a number of ScotWind projects, the government should also consider increasing the number of phases in which floating and fixed offshore wind projects can be constructed. The total capacity cap of the projects should be increased corresponding to the number of phases.

Table 1: Equivalent project capacity with alternative turbine capacity on existing projects

Project	Allocation Round	Total Capacity (MW)	Number of Phases	Number of Turbines	Size of Turbines (MW)	Developer	Equivalent Project Capacity with Turbines of Projected Size	
							15 MW	20 MW
Hornsea 1	FIDeR	1,200	3	174	7	Ørsted	2,610	3,480
Walney Extension	FIDeR	659	2	87	7.6	Ørsted	1,305	1,740
Beatrice	FIDeR	588	2	84	7	SSE	1,260	1,680
Theoretical Maximum Size Phased Project		*1,500*		*214*	*7*		*3,210*	*4,280*

Table 2: Projects under development Exceeding 1500MW 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	1,800
ScottishPower Renewables & Shell	Campion Wind	ScotWind	2,000
ScottishPower Renewables & Shell	Marram Wind	ScotWind	3,000
SSE Renewables, Marubeni & COP	Ossian	ScotWind	3,610
Sub-total			*10,410*
Total (MW)			**23,417**

Without changes to recognise the increased scale of projects as the industry has matured, these projects will be forced towards splitting large-scale offshore wind developments or adopting alternative offtake arrangements for different phases of projects, potentially leading to cost increases or delays to project deployment. Lifting the 1500MW cap would not require any change to legislation and could therefore easily be implemented for AR7. This would benefit projects bidding into AR7 and importantly also give visibility of the change to projects targeting later allocation rounds.

The benefits of phasing and reasons to raise the 1500MW cap include:

- Phasing has 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.
- A phased construction schedule allows projects to reach FID earlier in relation to Commercial Operation Date (COD) for the full project capacity, which in turn allows developers to place contracts earlier, secure suppliers' commitment and facilitate supply chain investment.
- Phasing provides a high degree of construction risk management for projects in unsheltered North Sea locations where the annual construction windows may be

shorter than for locations further south or on the East coast. This is particularly important for ScotWind projects that are pioneering construction in this new environment.

- The present 1500MW cap is entirely arbitrary and was introduced at a time when turbine capacity was significantly smaller. Larger turbines have allowed projects to substantially increase in scale whilst continuing to be developed and operated as a single, integral project.
- In the absence of phasing, larger projects have sought workarounds that have introduced greater commercial risks to developers whilst also presenting challenges to policymakers: the ‘merchant nose’ option is now constrained for future projects.
- In the future, an absence of phasing will force projects to be artificially split, requiring entry into separate CfD Allocation Rounds with multiple FIDs. This in turn brings greater allocation risk and commercial risk, along with more complex contracting that will be disruptive to both developers and supply chain.

Furthermore:

- **The phasing cap is a particular consideration for Scotland**, given the high volume of projects over 1.5GW coming through ScotWind. A number of these large ScotWind projects face challenging construction conditions. The limited number of projects greater than 1.5GW in England & Wales is solely a function of The Crown Estate’s leasing round conditions, rather than any technical or commercial constraint.
- **It is an immediate priority for fixed bottom projects**. Of the 19.3GW of ScotWind projects over 1.5GW, around 9GW are anticipated to be fixed bottom. These fixed bottom projects will almost certainly be the earliest to come forward, meaning that lifting the phasing cap for AR7 is a more pressing concern for fixed bottom than for floating (note: we therefore recommend that this issue is addressed for both technologies at this time).

We also believe that the government should urgently consider extending the Delivery Years for floating offshore wind and fixed bottom offshore wind to allow projects to better manage supply chain constraints and the risk of grid connection delays. Having just two years between the commercial operation date of two phases could be particularly challenging for floating offshore wind projects so allowing for an additional delivery year could allow projects to reach FID earlier.

The benefits of allowing for additional delivery years include:

- Accelerated investment in the supply chain, complementing wider efforts to stimulate growth of the UK supply chain. Taking FID earlier will enable developers to commit to orders with suppliers at an earlier date, providing the necessary certainty for further investment in the supply chain.
- Reduced costs in procurement and construction. The extended timeframe between FID and Target Completion Date facilitates longer lead times for securing equipment items and construction services, and more time to accommodate delays and overruns. Greater contingency and flexibility reduce costs for protections through performance guarantees, penalties and insurance.

Securing greater flexibility in the construction programme, through removal of the phasing cap and extension to the available delivery years, will reduce constraints in procurement, with following potential benefits:

- Enhancing the commercial efficiency for multi-phase projects but enabling larger projects to take one FID, hence reducing complexity and transaction costs. A single FID would also allow for earlier and larger contracts to be placed with suppliers, providing for the longer lead times and economies of scale that reduce suppliers' costs and facilitate supply chain investment.
- Reducing costs in procurement and construction, by:
    - minimising the likelihood of supply chain squeezes and bottlenecks that put upward pressure on costs.
    - providing for greater contingency in construction programmes, reducing costs for protections through performance guarantees, penalties, and insurance.
- Facilitating supply chain growth, by increasing the scope to utilise domestic suppliers, enhancing their opportunity to access the market.

Co-located generation and hybrid metering

16. To what extent do you agree with the identified challenges that the current CfD metering requirements creates, as set out?

We agree that the current CfD metering requirements restrict the flexibility available from sites with multiple technologies and categories. We agree with all the examples of restrictions given in the consultation document.

However, it is less clear how hybrid metering would work for offshore wind projects. DESNZ should clarify whether the Balancing Mechanism Units (BMU) boundary metering for an offshore wind farm is at the offshore substation or the onshore OFTO substation. If the former, it will be prohibitively expensive to co-locate other assets offshore behind the BMU boundary.

17. To what extent do you agree that introducing hybrid metering would support innovation and more flexible use of CfD-supported renewable generation?

We strongly agree that introducing hybrid metering would support innovation and more flexible use of CfD-supported renewable generation. Not every site with multiple technologies will necessarily apply hybrid metering, as this will depend on the specific assets and their operation in each case. But we expect that many such sites will take advantage of hybrid metering.

Offshore wind will require special consideration to remove barriers to colocation. The key barrier for offshore wind specifically is that the BMU boundary metering is at the offshore substation, at the boundary between the generating unit and the OFTO assets. This means that, even with the proposed changes for sub-metering in the AR7 consultation, you can only co-locate other technologies with offshore wind if these are geographically located at the offshore substation, which at present is economically unfeasible.

There are two solutions to this:

1. relocate the BMU boundary metering to the onshore substation which would enable the proposals in the consultation for sub-metering to work for offshore wind.
2. Utilise virtual metering to enable assets located at the onshore substation to be treated by the ESO/BSC etc as being behind the BMU boundary meter offshore. This would require more complex metering and communication protocols than option 1, but is well within Elexon's technical ability given it carries out similar tasks to enable virtual lead parties actions to be adjust supplier positions.

18. Specifically, to what extent could hybrid metering remove barriers to the deployment of low-carbon hydrogen?

See answer to Q.17. Since offshore wind will be the main power source for producing green hydrogen at scale, enabling offshore wind projects to co-locate with hydrogen production will be key to the deployment of low-carbon hydrogen.

19. Could you provide any evidence on the potential cost savings that could arise from introducing hybrid metering?

The direct cost savings include the avoided cost of registering and metering separate BMUs on a single site. Although not large, this will be helpful for smaller scale sites.

20. What would be the potential drawbacks or unintended consequences, including any potential for gaming, of introducing hybrid metering?

We are aware of the following potential drawbacks and unintended consequences of the proposed changes:

- Reduced visibility for the NESO in understanding the risk in delivery of the Final Physical Notifications (FPNs) for the settlement periods.
- Reduced operability control for the NESO to control the system.
- Reduced data transparency to the market on what could be significant generation and demand components.
- With CfD metering being behind grid metering, transfers within hybrid BMUs could lead to an increased risk of “gaming” the system with the reduced data transparency. However, the potential for gaming could be minimised by the requirement to continue to report CfD generation at the time of generation.
- More complex bid-offer pair pricing structures and implementation issues around different SEL (Stable Export Limit), MZT & MNZT (Minimum Zero and Non-Zero Times) between different technologies. Clarity on cost formation becomes difficult to show.

One area that will need further guidance and clarification is how the TCLC rules and other market behaviour regulations will be applied to a single BMU which has both generation and demand assets connected through it. It would not be fair or appropriate to assess the market behaviour of the BMU as though it were solely a generator or solely a source of demand. Hybrid sites form a new category of market participant and a bespoke approach is needed.

Section 2 – Considerations for future allocation rounds

How could the CfD support innovation in floating offshore wind foundation technology as the sector develops?

21. What are your initial views on the proposed approach to determining technological eligibility for established and emerging technology tariffs in the CfD scheme? Include any early concerns or potential risks you may foresee. We are particularly interested in any potential gaming risks or unintended consequences you have identified.

The priority for the offshore wind industry is to enable the step change in location that floating technologies can provide. Scottish Renewables therefore has concerns regarding the proposal to allow fixed foundation designs that are not established to compete with floating offshore wind foundation technologies. Our primary concern is that this could divert support away from the deployment of floating offshore wind projects, impacting the pace of innovation and cost reduction in the rapidly developing floating technology category.

Possible cost reduction pathways are modelled in a report from the Floating Offshore Wind Centre of Excellence. The report finds that, “rapid deployment of FOW [floating offshore wind] in the UK is key to reducing the cost of FOW in the UK in the short term (2020-2035). It is also likely to be key to maximising UK GVA in the medium and long term. In particular, the significant export opportunity may be lost if the UK is a slow starter in the industry.” With the 2030 target of 5GW of deployment, should floating offshore wind no longer be included as a specific technology on Pot 2, this would be misaligned with wider government ambitions for the technology.

However, we appreciate that ongoing innovation is not limited to floating technologies. There may be advanced fixed or hybrid foundation solutions which could prove cost-effective at certain water depths yet are denied a viable route to market as they are not eligible to compete with emerging technologies and benefit from higher administrative strike prices. Some within SR membership believe that it would be misguided not to allow a range of emerging offshore wind technologies to compete in Pot 2 in case the expected reductions in the price of floating offshore wind do not materialise..

22. If Government was to consider more tightly defining 'established fixed-bottom' offshore wind, with a view to then considering anything else eligible as an emerging foundation technology, do you have any initial suggestions on appropriate definitions or metrics by which to define 'established fixed-bottom'?

Whilst the majority of Scottish Renewables' members support maintaining dedicated support for floating offshore wind, there is not a consensus within SR membership about how best to address the challenge of defining different offshore wind technologies within the CfD framework.

Some believe it would be extremely difficult to define 'established fixed-bottom' sufficiently precisely to prevent incremental improvements from being put forward as emerging foundation technologies. There is a significant risk of over- or under-extending the definition of 'established'.

Others within membership support the proposed approach to negatively defining emerging foundation technologies by more tightly defining 'established fixed bottom' offshore wind as, whilst still challenging, defining established technologies would be easier than defining emerging technologies. This definition of established technologies should include descriptions and examples of these technologies as commonly understood by the industry. To protect against gaming and avoid undermining support for floating offshore wind, this definition would need to also include a clear definition of the common engineering principles which are fundamental to their function (and which distinguish them from other foundation types – i.e. floating). The creation and adjudication of this definition would need to be carefully managed by DESNZ to ensure its policy ambitions are delivered.

Others support the approach of using water depth as the criterion for what is (and what is not) 'established fixed-bottom' offshore wind. Some believe this technology agnostic approach should be adopted given the most cost-effective foundation solution for a given site could be fixed, floating, hybrid or other innovation. The fixed solutions could be entirely new, or an advancement of existing solutions. An attempt to define the specific point of innovation would be challenging and could risk unintended limitations on solutions which offer lowest energy cost to consumers. Conversely, using water depth as criteria, could enable market-led solutions, allowing fixed, hybrid and floating foundation solutions to compete on cost and deliverability basis. However, given the UK Government's support of floating offshore wind to date, this approach would mark a significant change in policy direction which could have major implications for floating offshore wind projects, the supply chain and port development.

23. The Government recognises the limitations of water depth for use in such definitions. However, should this be necessary, the Government welcomes views on the appropriate minimum depth requirement for emerging foundation technology deployment.

The limits of water depth for existing fixed foundations (particularly jackets) are primarily an economic choice rather than a technological limit, as evidenced by their use in very deep water by the oil and gas industry. However, using fixed foundations for offshore wind in deeper water still poses considerable technical challenges due to significantly differing load cases to the oil and gas application, and innovative fixed solutions are being developed to address these challenges. Therefore, defining a minimum depth requirement for emerging technology is difficult as the limit for existing technology is influenced by a large number of factors such as wind speeds and distance from shore.

If a minimum water depth is to be applied, then the key principle is that deployment could not be achieved with established foundation types. The world's deepest fixed wind project is Seagreen at 58m water depth. Our understanding is that there are fixed foundation projects using established technologies being developed in depths of up to 110m and possibly beyond. A more detailed review would be needed to confirm what is currently feasible in practice for fixed foundations and support would need to be limited to the innovative technologies targeting depths that are clearly beyond this. However, it is clear that any minimum water depth for emerging technologies would have to be no lower than 60m.

Setting an arbitrary minimum water depth for emerging technologies should also not prevent projects in water shallower than this minimum but with seabed geology or environmental issues which necessitate the use of floating foundations from being developed. To accommodate these cases, the 45m water depth minimum for floating foundations only should be retained.

How could the CfD support delivery of improved coordination of offshore transmission infrastructure?

24. Do you agree with the Government's assessment of bootstrap-connected projects?

We agree with the Government's assessment that no change is required to regulations to support eligibility of these projects, but that further work is needed:

- To clarify the costs of bootstrap-connected projects, to understand how they should be categorised in CfD auctions;
- To clarify any changes that may be needed to the contract or allocation framework.

25. Do you agree with the Government's assessment of the role of the CfD in the HM and OBZ models?

As a starting principle, SR believes that the current compartmentalisation of the transmission system between offshore and onshore should be removed as a priority. To deliver net zero efficiently over the long term, the focus should be on ensuring the development of an integrated system that does not differentiate between offshore and onshore-located connections.

SR agrees with the Government's assessment of the role of the CfD in the HM and OBZ models. However, we believe further work needs to be done to establish the potential role of the CfD in the OBZ model.

An HM model would act as the status quo for Offshore Windfarms (OWFs), so there would be no market changes for an OWF connected to an MPI compared to the counterfactual radial connection. On the other hand, an OBZ model imposes an increased risk for OWFs, and therefore compensation mechanisms are required to address the price and volumetric risk for OWFs.

For the role of the CfD in the OBZ model, we believe that the consultation has set out the key issues and challenges that arise from this combination. We agree that Scenario C (consumers take price risk) is the only one that would incentivise offshore wind MPI projects to build. Although this option does not address the volumetric risk, it does address the price risk, so it is a welcome step forward to modify CfDs for OWF-MPIs.

Given that under an OBZ market model, OWFs connected to an MPI will face higher balancing costs compared to the counterfactual radial connection, we think that a new Administrative Strike Price for OWFs connected to an MPI may need to be calculated. This is because higher balancing costs represent a new risk premium that OWF developers need to price in. Alternatively, the scheme could be extended to 25 years to better reflect the life duration of the asset and align the CfD with the MPI's regulatory regime. The 15-year duration for the existing CfDs (relative to the 25-year cap & floor regime for interconnectors, and longer asset life of the OWF) is not as much of an issue under a home market model as it is for an OBZ model. This is because, under the OBZ model, projects will be exposed to at least 10 years of potentially reduced revenue that may be difficult to recover, unless effective forecasts to account for this loss of revenue can be made and reflected in CfD bids and strike prices.

OWFs connected to MPIs may need a dedicated CfD pot with separate contractual arrangements. However, that would depend on the final market arrangements (HM or OBZ market) which will also rely on trading arrangements, regulatory regime, and the outcome of REMA. For example, an OBZ market with explicit trading would be very inefficient and will impose higher risk to the OWF compared to an OBZ model with implicit trading. In this case, an increased 25-year duration of the scheme or a new ASP would be important. However, there is a significant risk that creating a bespoke CfD arrangements for offshore wind MPI projects could provide additional incentives to the main CfD regime, distorting the incentives to locate and develop. This needs further assessment as part of the further work to be carried on the MPI-OBZ option.

Although we welcome the CfD changes proposed by DESNZ in this consultation, we encourage DESNZ to clarify how the volumetric risk and higher balancing costs for OWFs would be considered in the CfD design, as it is likely to be a key factor for OWFs considering whether to connect to an MPI. If OWFs are not fairly compensated for the loss of revenue of an OBZ model, OWFs will always prefer the counterfactual radial connection, which will maximise the utilisation of the wind farm and makes sure that it receives the GB wholesale price.

A key outcome of an effective MPI policy should be to enable OWF to compete on a level playing field regardless of how they are connected and to incentivise projects to connect in a way that reduces the amount of infrastructure required thereby lowering costs and community and environmental impacts.

All things being equal, OWF-MPI projects should have lower connection costs than radially connected projects as there will be an overall reduction in the amount of cable, offshore platforms and converter stations required which can form a significant proportion of a project costs, typically £1bn per GW.

In designing the framework to support OWF-MPIs it is therefore important to allow as much pass-through of these lower costs as possible. Subject to factors such as regulatory arrangements, trading arrangements and the market in which the OWF-MPI is operating, these lower costs could feed into a lower and more competitive CfD bid price, increase competition in the CfD auction and ultimately deliver savings to consumers.

We believe that whilst there are potentially additional volumetric risks to OFW-MPIs that should be explored, the primary way to address these is through efficient trading arrangements and allocation of capacity between bidding zones. We don't think these volumetric risks should be addressed in a way that limits the wider and potentially more substantial benefits from flowing back to consumers.

The flexible CfD proposal is therefore welcomed as this will provide the price certainty needed for OWF-MPIs, although we would recommend continuing to explore increasing the length of CfD contract for all projects (not just OWF-MPIs) under the REMA process.

As the OBZ in which the OWF-MPI is located will always match the exporting market price (i.e. the lower of the two market prices) in theory there is a risk that OWF-MPIs will need more CfD top-ups than OWFs receiving the HM price thereby increasing costs to consumers compared to radially connected OWF.

However, we feel that this could be outweighed by up-front CapEx savings, lower CfD bid prices and reduced environmental and community impacts. Also, GB is expected to be a net exporter from the end of this decade and will also typically be exporting at times of high OSW output thereby the OBZ price will more often than not be the same as the GB price. We therefore expect any additional CfD costs compared to radially connected offshore wind to be minimal.

26. Do you have any evidence on the additional costs and benefits to consumers of an OWF-MPI arrangement?

SR believes that OWF-MPI projects could deliver significant benefits to consumers, provided the CfD can accommodate these projects without unwanted consequences (perverse incentives etc.).

OWF-MPIs projects can enable more efficient deployment of offshore generation and transmission capacity relative to the use of discreet interconnector cables and direct-to-shore connections for offshore generation. In particular, OWF-MPIs can bring down deployment costs by significantly reducing the need for physical infrastructure, notably reducing the length of offshore cabling required and the need for converter stations. OWF- MPIs also enable the more efficient use of maritime space and, in doing so, help to decrease environmental impacts of offshore development.

Hybrid offshore projects - which connect more than one bidding zone – can bring socio-economic welfare improvements by allowing an increased market integration, more coordinated investment planning, these could add more flexibility to the system and decrease system costs. OWF-MPI can support the export of renewable generation to neighbouring countries that otherwise might have been curtailed at times of excess generation.

We would welcome an in-depth analysis of the potential impact of OWF-MPI projects.

27. Are there other options that could better address the issues outlined in this consultation?

As noted in our answer to Question 25, SR thinks that the CfD scheme would need to be modified to address the volumetric risk and higher balancing costs that the OWF will face under an OBZ market model.

Should CfD indexation be updated to better reflect inflation risks?

28. The Government is interested in views on whether a change in the inflation-indexation of CfDs could help to future-proof projects against macroeconomic shocks in future. Please provide supporting evidence where possible.

The experience of some projects securing CfDs in AR4 demonstrates that the current indexation is not always sufficient to protect projects against rapid cost increases during periods of macroeconomic shocks. We welcome the inclusion of this issue in this consultation.

In principle, we agree that a change in the inflation-indexation of CfDs could help to protect projects against future macroeconomic shocks. In practice, SR believes a bespoke commodity weighted index could likely offer the greatest improvement on current arrangements.

However, the detailed design of any alternative approach to indexation will need careful consideration so that an improvement is secured in practice and any changes to improve indexation should not come at the expense of maintaining indexation for the entirety of 15-year CfD contract.

It will always be challenging to use inflation indexation to fully mitigate shocks caused by widespread supply chain constraints that manifest in spiking scarcity prices of specialist components and vessels, beyond just increases in commodity prices. A key way to enable mitigation of such macroeconomic shocks in future is the setting of appropriate Administrative Strike Prices in each CfD Allocation Round.

29. Do you consider that a change to the way CfDs are indexed in future could better protect against inflation risk for developers, whilst also protecting electricity consumers from unreasonable costs? Please provide supporting evidence wherever possible.

In principle, we agree that a change to the way CfDs are indexed in future could better protect against inflation risk for developers, whilst also protecting electricity consumers from unreasonable costs.

If the existing index does not reflect the level of price risk from inflation that developers could experience, then developers are likely to incorporate an additional cost to cover the residual inflation risk when preparing bids for a CfD strike prices. The potential drawbacks for consumers from this approach include:-

- The projected inflation may not happen, in which case consumers are paying unnecessarily through an increased strike price.
- The strike price uplift applies for the whole CfD period, not just the periods with higher inflation (which may be shorter than the developer assumed).

Given these drawbacks, it is likely to be better value for consumers for the CfD to incorporate indexation that tracks actual inflation for developers as closely as possible. A bespoke commodity weighted index could likely provide the most accurate index.

Furthermore, commodity indexation is a two-way mechanism, where it effectively acts as risk sharing. Contract price would vary up/down depending on the spot price between bid submission and MDD (roughly FID). This means that both developers and consumers share the risk. This is similar to other auctions including Ireland and France.

30. Do you think electricity consumers, who ultimately fund CfDs, should bear greater construction risk through more comprehensive inflation protection to accommodate commodity price increases?

As noted in our answer to Question 29, it is likely to be better value for consumers for the CfD to incorporate indexation that tracks actual inflation for developers as closely as possible. This should be lower cost than developers incorporating a risk premium for inflation in CfD bids.

A further consideration is that, in the most extreme case whereby more comprehensive inflation protection is not provided and some CfD projects simply cannot proceed as a result of price increases, then consumers will not get the benefit of those batches of new low carbon generation. Although other generation projects will come forward in further CfD rounds, progress towards net zero will be delayed.

31. The Government is interested in views on the significance of commodity price risk for developers. How significant are these risks compared to labour costs, cost of debt and exchange rate risk?

It is our understanding that commodity prices are more volatile than labour costs and exchange rate risk. Commodity price risk is one of the most significant overall project risks. Cost of debt risk is another significant factor.

Capital Expenditure costs (including steel and copper) represent approximately 70% of LCOE for an offshore wind farm. Specifically, there are few critical commodities – steel, copper, aluminium and lead - which account for 11% to 15% of the actual total project cost. Contractors and suppliers will not provide binding offers before the auction and bidders will be exposed to general inflation of capital expenditures between bid submission and commencement date, in addition to fluctuations in the price of steel and copper.

32. The Government is interested in views on how to define the period in which renewable generating projects are most likely to be exposed to fluctuations in key input costs, and therefore benefit from greater inflation protection. Please provide supporting evidence wherever possible.

Most key input costs are fixed by the time a project takes its FID. The CfD auction process takes up to around 6 months from the submission of bids to award of CfD and FID coincides roughly with the end of the 18-month CfD Milestone Delivery Date.

As a result, costs remain open for about 2 years between the submission of a CfD bid and reaching FID. This is the period that the project is most exposed to fluctuations in costs. Before this, cost increases can be incorporated in the CfD bid. After this, contracts with supplier will lock in most costs or link cost changes to a recognised index, such as the CPI used in the CfD itself.

We recommend that the period of greatest cost fluctuation exposure is defined as the period between the submission of CfD bids and the CfD MDD. If indexation under the CfD cannot be backdated to the submission of bids, then the starting date should be the date of signature of the CfD.

33. The Government is interested in views and evidence on whether indexing strike prices to PPI during the construction phase of a project would better reflect increases in project costs than CPI. Please provide supporting evidence where possible. We are interested in an assessment of both the short-term and long-term impacts that this change could have.

Scottish Renewables believes a bespoke commodity-weighted index could offer the best option for indexing strike prices.

Like CPI, PPI is a complex index with many inputs. Although the composition of PPI is a somewhat closer fit to the composition of cost categories for the construction of a renewable generation project, it still contains many inputs that are not linked in any way to the project costs. As a result, there is still a significant probability that the PPI will not reflect the actual cost increase experienced by a developer.

In addition, PPI has a significantly greater volatility and wider range of values compared to CPI, including often tracking below 0. (If PPI were to be used for indexation it would therefore have to be floored at 0 to prevent strike prices being eroded.) That means that the difference between actual costs and the index could be much larger with PPI compared to CPI. It makes an extreme case (in which actual costs are rising, but the index is falling) more likely. This reduces the effectiveness of indexation in reducing the financial risk to the project. This increased risk would then be priced into strike price bids.

As a widely recognised and accepted index, CPI indexation throughout the lifetime of a project has key advantages. These advantages include 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. Additionally, supplier contracts have no general inflation indexation mechanisms and are renegotiated at regular intervals. Cost increases caused by, for example, labour costs, inbound transport costs and energy prices do not affect costs immediately 1:1 but will flow through over time.

For these reasons, we cannot recommend that PPI is considered further for use in the CfD. However, we would welcome further analysis of the impacts of using PPI floored at zero for indexation in the construction phase of projects to support this conclusion.

34. The Government is interested in views and evidence on the implications of indexing strike prices to PPI in the construction phase of a CfD project on investor confidence, and the overall effect this could have on project hurdle rates.

This risk of a mis-match in the PPI trend and the trend in actual costs for the project is increased by the greater volatility of PPI. For example, unlike CPI, the PPI is regularly negative in value. Because PPI values can change quickly, there is a higher risk of a mis-match arising, compared to an index that changes more slowly and is very rarely negative.

As a result, investors will find it difficult to manage this new risk and it is likely to increase, rather than reduce, the project hurdle rate.

Indexing strike prices to PPI in the construction phase of a CfD project could negatively impact investor confidence because of the following reasons:

1. Steel prices are subject to extreme volatility at present following supply chain issues and the start of war in Ukraine. The price of steel has trebled in recent years. General Inflationary indices like PPI are not well correlated to steel prices and hence indexing strike prices to PPI will not provide any benefits to the developer while subjecting them to the risk of strike prices going negative frequently as seen in the trends presented in the consultation.

2. The forecast of future revenues for lenders to size debt on will be less certain given the higher volatility of the PPI, as is ultimately the free cashflow for equity, and lenders will test this with downsides on PPI movements reflective of such volatility. So, it may restrict debt capacity to a certain degree.

35. Over the last 10 years, PPI has historically been more volatile than CPI, but has also tracked higher overall. What effect do stakeholders think this could have on CfD bids? Please provide supporting evidence wherever possible and assess both the short-term and long-term impacts.

The risk of a mis-match in the PPI trend and the trend in actual costs for the project is increased by the greater volatility of PPI. Because PPI values can change quickly and are sometimes negative, there is a higher risk of a mis-match arising, compared to an index that changes more slowly and is almost never negative.

Investors will find it difficult to manage this increased risk from the PPI index and it could increase, rather than reduce, the project hurdle rate, compared to the use of CPI.

36. What trade-offs (for example, partial indexation later in the contract) or protections should the Government consider to retain consumer value for money?

Partial indexation and other options to limit the increases in payments from a switch to PPI would be a complex measure to take for an index that will only be applied during the construction period. They would make financial analysis more complex, for a limited benefit, if any, for consumers under rare circumstances. If full indexation were to be removed, developers would likely include their own view of inflation into their bid price. There is risk of inaccuracies in this forecast resulting in higher strike prices, as has been the case in other markets (for instance the RESS 1 in Ireland). Depending on the magnitude of the uplift in strike prices, the introduction of partial indexation could in fact have a net negative impact on consumers.

We don’t consider that these measures should be applied in addition to an index. Either the index can be relied upon as it is, or it should not be used.

37. Are there alternative proposals that could offer similar benefits that the Government should explore and if so, what are these and why? Please provide supporting evidence.

A number of support schemes for renewables in other countries use a bespoke index, based on a basket of the main commodities, for renewable support schemes. Some use indices for labour and service costs in addition to raw materials and components.

This would be the most effective approach to applying an alternative index to CPI, but would require considerable work to establish. A further complication is that a bespoke index would be required for each CfD technology, as the mix of inputs are significantly different.

Another consideration is that the majority the supply chains for renewable projects are global, not UK based. As a result, a global cost index would be a more accurate reflection of the changes in project costs, but this would further increase the complexity of the index.

Nonetheless, the examples from other countries demonstrate that it is feasible to implement a bespoke index for support schemes. We recommend that this option is considered further. Particular consideration should be given to introducing a bespoke index for offshore wind given the scale of the projects being developed and the fact that offshore wind having a separate funding pot should mitigate level playing field concerns.