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RWE Renewables

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Dear Offshore Coordination Team,

REF: RWE's response to the consultation regarding changes intended to bring about greater coordination in the development of offshore energy networks

About RWE

RWE Renewables, the newest subsidiary of the RWE Group, is one of the world's leading renewable energy companies. With around 3,500 employees, the company has onshore and offshore wind farms, photovoltaic plants and battery storage facilities with a combined capacity of approximately 9 gigawatts. RWE Renewables is driving the expansion of renewable energy in more than 15 countries on four continents. By the end of 2022, RWE Renewables targets to invest €5 billion net in renewable energy and to grow its renewables portfolio to 13 gigawatts of net capacity. Beyond this, the company plans to further grow in wind and solar power. The focus is on the Americas, the core markets including UK, Europe and the Asia-Pacific region.

In the UK, RWE employs over 2,600 people with a diverse operational portfolio of onshore wind, offshore wind, biomass, hydro and gas - generating enough electricity to power 10 million homes. The UK plays a key role in RWE's strategy to grow its renewables business and to become carbon neutral by 2040. This includes the Triton Knoll offshore wind farm currently in construction off the coast of Lincolnshire (857MW, RWE share 59%) and the Sofia offshore wind farm in development (1.4GW, RWE share 100%). RWE and its project partners also recently signed Agreements for Lease with the Crown Estate to extend the existing offshore wind farms Gwynt y Môr, Galloper, Greater Gabbard and Rampion. We were also recently successful in securing Preferred Bidder status for two further offshore sites amounting to 3,000MW in the recent Round 4 Leasing Round by The Crown Estate.

Please find our response to Ofgem and BEIS' consultation questions below.

Kind regards,

Nicola Percival

Senior Regulatory Affairs Manager, RWE Renewables

RWE

Early Opportunities questions

Question 1: Are there any concepts we have not identified developers (as defined in this chapter) may wish to progress?

It is our understanding that these concepts were identified in liaison with developers via the "opt-in" process coordinated by NGESO. If further, deliverable concepts do arise then these could be added.

All the concepts set out by Ofgem assume electrical coordination where connections are integrated together. Throughout the consultation Ofgem uses "coordination" and "integration" interchangeably. NGESO did the same in their Offshore Coordination Project final report.

In our view "coordination" and "integration" refer to different ends of a sliding scale; integration refers to electrically integrated systems. This could be an MPI, or electrically shared transmission assets between two or more wind farms. Coordination of infrastructure, which already occurs (eg, between RWE's Sofia Offshore Wind Farm and SSE's Dogger Bank C Wind Farm), can refer to concepts where cable routes, for example, are shared but the transmission system for each wind farm remains electrically separate. In this way coordination can still deliver reduced consumer costs, and reduce impacts upon local communities and the environment compared with entirely uncoordinated connections.

Coordination, described in the above paragraph, is far less commercially risky than integration in a market design where all offshore wind farms are competitors in CfD auctions. Coordination also reduces the risks of stranded assets, which is a huge advantage in the Early Opportunities workstream which seeks to deliver both coordination and GWs without undermining government targets and investor confidence. Solutions involving integration are also far more likely to require extensive code modifications, as Ofgem recognise in the consultation.

An electrically separate but still coordinated approach also brings other benefits. For example, the cabling requirements of either electrically integrated or coordinated transmission between two neighbouring wind farms connecting onshore may be of similar scale in terms of infrastructure and can still go to a single substation of similar size regardless of whether integration or coordination is pursued.

To this end we perceive a number of variations to the Shared Offshore Transmission System model set out in figure 4. In addition to the model in the diagram projects may retain separate offshore platforms due to geographical constraints and/or retain separate cables but coordinate the installation and location of the onshore infrastructure. The degree of integration will vary dependent on the circumstances of each project.

For all the concepts set out in the consultation there is a level of detail below the schematics Ofgem have produced which will affect how options sit in the existing codes.

For example whether an offshore transmission circuit is HVAC or HVDC, single or multiple circuit, and whether there is capacity sharing where the sum of the potential capacity flows exceeds the offshore transmission capacity (eg, multi-purpose interconnector ("MPI").

Question 2: Should anticipatory investment risk be shared with consumers? If it should, what level of risk is it appropriate for consumers to bear?

Yes, we agree that anticipatory risk must be shared with consumers, as consumers will be the primary beneficiaries of shared connections through lower capital costs and reduced societal and environmental impacts.

As the consultation notes, there are very few examples of Anticipatory Investment ("AI") being undertaken within the existing framework where the risk is almost entirely allocated to the generator. As a result, AI that has occurred is generally (if not exclusively) by generators undertaking that AI for their own future development pipeline. We are not aware of any examples of AI by developers which has been undertaken primarily for the benefit of third parties.

The level of risk consumers should bear should be carefully considered such that it ultimately delivers offshore transmission and generation projects in the interests of consumers, and as a consequence meets the policy assessment criteria of Appendix 3 of the consultation.

This could well be more complex than "the minimum required to secure AI by developers" as Ofgem suggests in Section 2.42 of the consultation. Rather than a standard percentage, this could be a methodology for determining consumer risk share within the CUSC which can be applied to different concepts of integration. Therefore the allocation of risk between different parties, including the consumer, could change in its magnitude from project to project - dependent upon the risk profile of the particular project(s) the methodology is applied to. This would be in line with the principle that risk should be borne by those best placed to manage it.

Question 3: For concepts that intended to provide a wider system benefit, eg by mitigating an onshore constraint, how should the need for investment be demonstrated by the developer?

RWE broadly agrees with the principles of assessing anticipatory investment ("AI") for approval. Ofgem will need to see evidence that it is worthwhile and ultimately delivers on the objectives of OTNR, and net zero. Ofgem should have a net zero duty in order that this be a strategic assessment, focused on getting to net zero at least cost to the current and future consumer – rather than focused on short-term costs, which doesn't align well with the OTNR objectives.

Some Early Opportunities concepts have the potential to deliver a reduction in the amount of offshore transmission infrastructure needed (compared with a radial connection counterfactual) and should be relatively straightforward to assess. The main challenge being both whether the risk level is acceptable to the consumer and the developer having full confidence in Ofgem's cost assessment process to ensure full Wider Network Benefit Investments ("WNBI") costs can be recovered.

It should be recognised that, in the short-term, avoiding infrastructure in one place generally creates more infrastructure somewhere else. It is overall capacity (MW) that generally drives number of cables, size of substations etc. and it is spare capacity in the onshore network which broadly drives the location of onshore connections. The latter is a long lead time item, and therefore ESO/TOs will largely be working with what is already in planning for Early Opportunities projects. Moving from HVAC to HVDC technology can reduce the number of cables, but it also introduces the need for HV Converter stations.

Early Opportunities concepts that are to provide a wider system benefit should be cost-benefit assessed by NGESO as part of the connection agreement development/revision phase to show that the proposals are worthwhile. This will require some input on costs from the offshore developers and should make comparison to other options available to NGESO to provide the wider system benefit. In line with OTNR objectives this must also take into account factors that are not purely cost related such as local community impacts, consenting issues and deliverability. For example, there is potential for sharing compensation requirements mandated via consenting activity through Early Opportunities concepts. These may also have the ability to provide a wide range of benefits of designated sites/species beyond the electrical wider system benefits that Ofgem focus on. How will Ofgem and NGESO include such benefits in their assessments?

Noting that NGESO, the transmission owners and Ofgem already have a wealth of experience in such matters, but that development and submission of needs cases and the subsequent decision (approval or refusal) can take a long time. Therefore, it is important to have regard for the urgency attached to the Early Opportunities' projects need for clarity, and suggest a clear timetable for this process be established which supports the delivery of 40GW by 2030. This will need to be done with the project programmes of the Early Opportunities concepts "base case" connections at the forefront of the deliverability assessment.

For example, we assume that for the Early Opportunities concept of the HVDC bootstrap combined with offshore generation the shared offshore transmission would be delivered by the relevant transmission owner, and therefore the need for investment would be demonstrated by that transmission owner with inputs on costs and other factors from the relevant offshore developer(s). In such an example there are further questions regarding who delivers the local assets which connect the wind farm to the bootstrap (generator-build, as per the OFTO regime?).

Question 4: What options are available to developers in demonstrating a reasonable expectation they intend to connect to the system?

Ofgem state that "anticipatory investment" as referred to in the consultation is for known projects and that "highly anticipatory investment" refers to as-yet-unknown potential projects. In this context, the Early Opportunities workstream is designed to deliver the former with regards to known projects – primarily, but not exclusively – in a developer-led process.

As projects progress through the development process, the ability to demonstrate a reasonable expectation of connection to the system increases. Conversely, the projects' ability to change arrangements, such as connection location and capacity, decreases without incurring significant costs and/or delays decreases at a similar pace. For known projects connecting by 2030, the window of opportunity to change arrangements is open – but certainty is required urgently.

It should be noted that delivery of 40GW by 2030 needs to be by way of steady delivery of GWs throughout the 2020s, and that an attempt to deliver this target in a "lumpy" way (ie, connect everything in 2029 and 2030) would have major implications for supply chain and cost, amongst other things.

In the Early Opportunities workstream project shareholders will not pursue options which negatively impact project programmes to participate in their targeted CfD auction round, or which risk generating excessive project DEVEX costs which are not recoverable. The developers of potential Early Opportunities project concepts need urgent clarity that the excess costs of pursuing of a number of development options (including different connection locations, requiring different consenting envelopes, each carrying different risks and costs) will be recoverable – and when these costs can be recovered.

These are crucial issues to acknowledge to ensure that the 40GW by 2030 target is met, bringing with it many benefits to continued cost reduction, and the further development and continued sustainability of a domestic supply chain. The consumer benefits of this are tangible.

Developers that have signed an Agreement for Lease with The Crown Estate or The Crown Estate Scotland have already begun the process of signalling their reasonable expectation that the project intends to connect to the system. This might have significant financial liability attached to it, which gives a strong signal of commitment. In addition, Connection agreements with NGESO will require User Commitment (demonstrating a financial commitment) as well as set out a programme of works for the developer and TO, including a connection date and location.

As the detailed network design and consenting work is progressed – both by the incumbent TO onshore and the developer for the offshore and onshore associated assets - it will become increasingly difficult to maintain project programme towards an agreed connection date if the goalposts are shifting.

Where Early Opportunities concepts cannot be solely developer-led (for example those which include the TO-owned HVDC bootstraps), for these Early Opportunities projects the relevant TO should be proactively discussing making imminent offers for offshore connection points rather than offering onshore connections, if developers are amenable to this approach in their specific situation. It should not be left to Developers to drive this; indeed developers cannot drive this. If the same connection dates can be achieved by connection to a future bootstrap, for example, that option should be offered as soon as possible.

Question 5: To what extent do you agree with our proposals to remove barriers to the Early Opportunity concepts? Please explain your answer.

Incentivising delivery of developer-led shared offshore transmission concepts

We welcome the removal of Generator Focused Anticipatory Investment ("GFAI") from the Codes as set out in Section 2.52 of the consultation and concur that all anticipatory investments should be treated in the same manner.

All the Early Opportunities concepts set out could involve integration (ie, electrical system sharing) between generators and/or other parties. The timescales for delivery, and the lack of commercial incentive to integrate rather than coordinate (see also our response to Question 1) suggests that integration is more likely in the Pathways to 2030 and Enduring Regime workstreams. This consultation sets out steps to enable integration by 2030, but no commercial incentives to mitigate the increased risks of doing so. See Appendix 1 to this consultation response for further detail. The Early Opportunities projects need to progress at pace to keep to project programmes already set out and agreed with NGESO in order, to connect by 2030 and for us to meet the government's 40GW by 2030 target.

We agree that the sharing of offshore transmission, and/or associated onshore transmission by generators and other parties is likely to represent an opportunity to reduce overall costs, relative infrastructure requirements and environmental benefits for stakeholders when looking ahead to 2050, and could be a common approach if appropriately incentivised.

As we set out in our response to Question 1, coordination is far less commercially risky than electrical integration and it will not always be necessary for delivering on the OTNR objectives to integrate rather than coordinate. If electrical integration is to be realised as part of Early Opportunities it must be incentivised, but the proposals set out by Ofgem in this consultation do not set out how this will be achieved. An active decision by BEIS and Ofgem to incentivise and promote sharing of offshore transmission by generation and other parties (subject to appropriate assessment and approvals) would meet all of the network design criteria of Appendix 2 of this consultation and the OTNR policy assessment criteria, as set out in Appendix 3 of the consultation, namely:

- It is readily deliverable (subject to Code changes) and can significantly contribute to Net Zero and 2030 targets.
- It aids deployment with no adverse effects on competition and risk can be sensibly apportioned.
- It results in a significantly reduced environmental and societal impact through reducing the amount of offshore transmission infrastructure.

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- It results in positive consumer and transmission benefits by reducing offshore transmission costs.

This would therefore be supportive of Ofgem's legal duties to protect current and future consumers.

Ofgem propose in Section 2 of the consultation that AI risk should be shared between developers and consumers, where appropriate. In our answer to Question 2 we express support for this. We are therefore extremely concerned by Ofgem's proposals in Table 6 of Appendix 1 which appear to suggest that, much the same as the current approach (through GFAI), all the risk for shared transmission concepts which do not involve an MPI will be placed with the generators (or other connecting parties). Different treatment of Early Opportunities projects in this way could introduce undue distortion, as interconnector developers would face less risk than other developers.

This suggests that if Ofgem believe the benefits accrue to the connecting parties then they will take all the risk. This is also suggested by Figure 11 that where Ofgem does not see a system benefit (presumably this refers to the electrical system), the expectations are that the developers will take all the risk. If this approach is taken to AI risk, it can be expected that very little coordination or integration of offshore transmission will occur – much as is the case today.

Sharing of offshore transmission infrastructure by generators and other parties may in some cases result in (economic) benefits to the generators, but in others may not (but is pursued regardless due to the perceived reduction of other risks, for example consenting).

However, this should not be a focus of the assessment by Ofgem because irrespective of this, sharing of offshore transmission will invariably be of benefit to the consumer both economically (savings passed on through lower CfD bids and OFTO costs), local residents through potentially reduced need for onshore infrastructure development, and with the wider OTNR objectives in mind. It is therefore essential that shared offshore (and/or associated onshore) transmission concepts are incentivised along with other concepts through assessment and approvals from Ofgem and sharing of risk with consumers, so as to deliver the best outcome of the OTNR. Broader considerations, such as those regarding CfDs outlined in this consultation must also be considered alongside other incentives.

Without this, we believe that integration (sharing of electrical systems) will be significantly hampered and reduced compared to its full potential. This would undermine delivery of the OTNR objectives.

We note that the treatment of TNUoS costs for the Generator in an interconnector led MPI concept are unclear. We would welcome more detail from Ofgem on this element and would be interested to understand how a level playing field can be maintained across the different MPI solutions, especially where developers may be competing against each other for a CfD.

Ofgem cost assessments & approvals

All types of AI must be assessed and approved by Ofgem ahead of OFTO transfer processes and cost assessment. An appropriate way to deliver this could be via "Gateway Assessment(s)" at particular milestones in the development cycle of a project(s).

Each of these assessments would result in approval (if appropriate) to proceed with the anticipatory investment plans, essentially providing confirmation that it will not be a disallowed cost at the final cost assessment as part of the OFTO transfer process.

Without such a process then developers considering undertaking AI in the Early Opportunities process will likely choose not to proceed, as the enablers resulting from Code changes alone will not incentivise electrically integrated transmission.

These assessments by Ofgem should be based on the concept of "economic and efficient" which should not just focus on cost savings for the electricity system and network, but also on the benefits environmentally and for local communities, as well as the longer term impacts on reaching net zero.

There is a fundamental need for Ofgem to approach cost assessment holistically i.e. to ensure that the cost-benefit analysis and impact assessments it undertakes should not just focus on the short-term costs and benefits to consumer bills, but also consider the legal requirement to hit net zero by 2045 in Scotland and 2050 across the UK as an equally important requirement. Ofgem's focus should be on the legal requirement to hit net zero and, in line with Ofgem's duties, at least overall cost to the current and future consumer, and whether any decisions taken by Ofgem are strategically best for the current and future consumer in the context of net zero. The difference between the former (short-term focus) and latter (strategic focus) is truly fundamental in its approach, and only the latter can be viewed as in the best interests of the future consumer (most of whom are also current consumers).

Such assessments carried out by Ofgem will need the support of NGESO (and, in time, the Future System Operator) and this could be an agreement that the anticipatory investment is appropriate, economic and efficient, or, a more detailed cost benefit analysis as might be required for a Quasi-bootstrap or bootstrap concept.

CfD & Competition

The current CfD rules have brought forward world-leading levels of investment in offshore wind, at incredibly low costs to the consumer. However, they seek to ensure that all individual offshore wind projects are in competition with one another. This is a difficult concept to marry up with a drive for project integration, and to an extent coordination too, for several reasons.

There are legal and commercial issues with sharing sensitive information with competitors. This could create legal issues, or compromise CfD bidding competitiveness.

BEIS and Ofgem need to consider how the necessary specifications for project integration/coordination can be shared, without influencing competitors' bidding strategies or creating conflicts of interest.

There will also be legal and commercial aspects associated with agreeing private treaty financial compensation aspects with common landowners and the ability to use compulsory acquisition powers. This may result in escalation of costs affecting CfD bidding competitiveness, if different projects are being played off against each other without a co-ordinated approach.

Furthermore, particularly where electrical transmission system integration is being taken forward, developers' CfD bids will be co-dependent on other projects being successful in their CfD bids.

Finding solutions to these issues, whilst retaining the current CfD design, is essential to creating an investible framework for developer-led integration at lowest cost to the consumer. See Appendix 1 to this consultation response for further detail.

Tender process cost transfer

RWE supports Ofgem's proposal that the associated risk and cost should be appropriately shared with the consumer when proceeding with AI (see our answer to Question 2).

Ofgem identify in paragraphs 2.40 – 2.41 and Figure 10 a potential cost reimbursement process. This process will require new regulations and is quite different to current arrangements. It could also require careful consideration across coordinated projects that are delivered in stages, as commissioning of subsequent connectees may be beyond a 24-month generator commissioning timescale of the first connectee. This impacts upon primary legislation.

Under the current regulations, a developer who has transferred offshore transmission assets to an OFTO is reimbursed the "Final Transfer Value" by the OFTO. Offshore Local Transmission Use of System charges are then levied by NGESO to recover the transmission costs, these being partly made up of sums from the relevant and newly connected offshore generator(s) and also from other users of the transmission system (effectively the consumer). NGESO then allocates the correct sums to the OFTO and other transmission owners.

Ofgem's proposals appear to show the payment of the Final Transfer Value (to 'Developer 1') including an OFTO payment, plus the transfer of User Commitment sums (underwriting sums) from 'Developer 2' (understood to be a connectee at some stage to the new offshore transmission) to 'Developer 1', plus payments to 'Developer 1' (who has just transferred the asset to the OFTO) from Transmission Use of System charges.

There is no arrangement currently whereby Transmission Use of System charges are collected and allocated to a developer. Additionally, in Ofgem's proposal, User

Commitment is lodged by developers (in this case Developer 2), but these sums are only collected should the developer terminate its agreements to connect. In such a case, NGESO collects the sums and uses them as cover for stranding. There is no arrangement in the current rules whereby User Commitment sums are used to make payments to other developers.

RWE broadly supports RUK's proposals regarding how a revised user commitment and risk sharing process could work in practice to enable anticipatory investment.

Question 6: Do you believe a Significant Code Review is required to give effect to a potential decision to 'share' AI risk between consumers and developers?

A fundamental concern with deliverability of the code changes necessary to enable the six concepts is the time it takes for Code changes to be progressed from inception to implementation.

Following discussion with industry, Ofgem, BEIS and ESO over the course of this consultation period it has become clear that there is appetite to ensure that the necessary code changes to enable increased coordination/electrical integration are delivered in the necessary timescales. To do this a framework will need to be developed, within the scope of the existing governance processes, with the explicit purpose of supporting delivery of Early Opportunities concepts.

Work is ongoing regarding exactly what this will look like. Whether an SCR is necessary or not depends upon whether the framework for delivery requires it.

The framework would need to facilitate broad discussions across all the aforementioned stakeholders regarding the intent of the changes, identify the areas of each Code which require amendment and lead to the development of as few Code modification proposals as possible to be taken through the code modification process.

This is likely to require ringfenced ESO and Ofgem resource. We suggest that ESO's work to identify the code changes needed to deliver the Early Opportunities concepts are completed and shared with industry in Q4 2021.

Note that this will not solve the issue of a lack of incentive to coordinate/integrate under some Early Opportunities concepts, but it would ensure that the necessary changes to enable coordination/integration to be taken forward are made in time. The issue of a lack of incentive remains in many cases.

Question 7: Do you agree with Ofgem's proposed approach to deliver the objectives of the Early Opportunities workstream?

Please see also the response to Question 5 and 6. Our response to this question relates to the process of delivering the necessary changes.

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We note that the projects under consideration are likely to be entering CfD Allocation Rounds 5 and 6, therefore project development and key decision points will continue in parallel to OTNR activity. We believe that, alongside a clear commercial case to trigger delivery, early opportunity concepts require clear regulatory guidance and early barrier removal. Ofgem should aim to consult on the final models as soon as possible, with a clear timeline for implementation. We also believe that clear risk analysis should be published alongside the final proposals, referring to the objectives in Appendix 3 in the analysis.

CUSC

We are concerned that following the normal open governance processes, with an expectation that individual parties and NGESO will bring forward individual and separate modifications, will take too long. Therefore we suggest in our response to Question 6 that there is dedicated, additional resource at NGESO and Ofgem which is ringfenced for delivery of the OTNR modifications on pre-determined timescales. In recent years, even relatively straightforward modifications – particularly to the CUSC – have frequently taken 12-24 months to deliver, often causing implementation dates to slip.

The deliverability of Code changes (alongside incentives, see our answer to Question 5) is fundamental to enabling projects in the Early Opportunities workstream to be able to deliver integrated solutions, without causing delays to projects. We note that a level of AI risk is already shared with consumers regarding onshore investments and that a low level of transmission costs are already shared with consumers regarding offshore infrastructure, indicating that this concept is not new.

Grid Code and SQSS

Changes to other codes may be more difficult to understand and to bring forward in short timescales. We therefore believe that some derogations are likely to be necessary. This is particularly the case with the Grid Code which is already overly complex. In relation to the SQSS, this is in need of review and a level of wholesale change in relation to offshore wind and offshore transmission, therefore derogations against the existing SQSS are likely to be necessary, at least as a holding position. Developers will need a dedicated resource from NGESO to understand the key issues in these codes and decide on how best to overcome them. See also our answer to Question 6.

Other Codes

It is not clear whether other codes may be affected, notably the STC and BSC. This will need to be assessed also with NGESO and a best route forward developed. This may also require derogations.

Pathway to 2030 questions

Question 8: We consider that a holistic design will result in a more coordinated, economic and efficient network. Do you agree? Please give reasons for your answer.

We agree that the Holistic Network Design (HND) can support the design and delivery of a more coordinated and integrated onshore and offshore network. This requires the use of the HND to be well-understood and executed, otherwise its potential to be realised will be reduced, or even lost. The HND must also ensure that delivery of 40GW by 2030 is sustainable for the further development of the GB supply chain and CfD auctions, and therefore must ensure that the pipeline of delivery is regular throughout the 2020s.

The ESO holds the necessary skills for design, however they are not best-placed to understand how the network will be consented and constructed. In GB that knowledge is held by developers and the incumbent TOs (in the existing frameworks). This knowledge and experience is essential to ensuring that the HND is an essential part of the process to ensure that the necessary network assets are brought forward in the correct order and at the right time.

The current system incentivises offshore wind developers to build the most economic and efficient grid connection within the scope of the regulatory environment. Under the Developer-build OFTO model (the only one used to date) the developer will consent, design and construct the windfarm and the associated offshore and onshore transmission infrastructure in the most efficient and innovative way possible – taking into account both the development and operational phases. If these elements are broken up, and potentially become the responsibility of different third parties, then the correct incentives must be in place to ensure that efficiency and innovation are at the forefront of design and delivery. The HND must ensure that the designs it produces can be consented, and that the technology to deliver the designs is available when it is needed.

Paragraph 3.25 outlines that "*a classification decision will have to be made to determine whether to apply to onshore or offshore licencing regime*." Who will make this decision and what will the basis of this decision be? When will this decision be made? Without clear delineation of responsibility, there will likely be a high risk of delays.

Paragraph 3.26 states that "*We expect the HND to be delivered according to a robust methodology cognisant of, and consistent with, the requirements of the RIIO processes*." These requirements are focussed on the economic costs and benefits of network investment decisions, and play down the role of anticipatory investment and the benefits it can bring, particularly in the context of net zero. It is essential that the Central Delivery Group, and Ofgem in its RIIO processes, using the HND and other resources, are able to take into account long-term network requirements and accept a level of risk on AI, including highly anticipatory investment. The Generation Map will assist with this, subject to that which is discussed in our answers to Questions 4 and 5. It is not clear what the remit or authority the Central Design Group has within the context of the other TO/SO licence conditions. For example - will the recommendations from the group give stakeholders sufficient confidence to progress with investment to progress the proposed reinforcements? Will Ofgem seek to approve the outcome of this group in order to provide such confidence?

The scheduled publication date for the HND may be prior to the announcement of the ScotWind Leasing Round outcome. The HND must cater for all credible outcomes of ScotWind when it is published so that it does not require substantial re-work when ScotWind is finalised.

We note that the government is consulting on the future of the ESO, and possible functions include "holistic and coordinated (onshore and offshore) network planning". We agree that that the Future System Operator should have this function, but also work closely with TOs and developers on the delivery of the network.

Paragraph 3.5 outlines that "*we envisage the new approach will speed up later development steps, including the consenting process…*". However consenting is not within the remit of Ofgem to determine, and there is no evidence available that we are aware of to suggest that this aspiration is realistically achievable. The planning and consenting processes (in England and Wales) are based on Statutory timelines, with a clearly defined process.

In Scotland there is an entirely different consenting regime to that in England and Wales and, in some instances, far less pressure on coastal land use compared to for example East Anglia and Lincolnshire. Development delays represent a significant cost - that ultimately gets paid for by consumers - and will have adverse impacts on the reduction of greenhouse gas emissions.

Finally, it is important to highlight that delivery of the required upgrades to onshore transmission system infrastructure will be the critical path for all Round 4 sites and ScotWind sites that will be delivered before 2030, and therefore any network delivery delays will have a direct knock on to the delivery of 40GW by 2030 in GB and Scotland's own target of 11GW by 2030.

Question 9: Do you agree with the planned work for a detailed network design offshore?

AND

Question 10: Who do you believe is best placed to undertake the detailed design for assets that are in offshore waters?

It should be noted that for the Leasing Round 4 projects the early stages of offshore Detailed Network Design ("DND") has already begun, and is being undertaken by the winning developers – in line with the current framework. Given the option payments required for Leasing Round 4 projects efficient development is a priority, and where development expenditure made in good faith to date is rendered unnecessary due to subsequent changes made by NGESO these costs should be recoverable.

In the current framework Offshore DND and pre-construction phase works will largely be undertaken with a significant crossover in their timescales by developers, as a way of maximising project optimisation (as is also the case for onshore DND and consenting by the incumbent TOs). If these two processes are undertaken by separate parties, this would likely introduce inefficiencies and unnecessary delays.

Therefore introducing a DND phase may simply create delays, and introduce an additional layer of work which would then be potentially repeated at a later date when the delivery body starts its work and more detail is known. For example, the DND needs to include the specific technical requirements of connecting the offshore wind farms, which may not be available at an early stage.

Some of the delivery models below require an element of DND to work (eg early OFTO tender). Whilst these deserve further attention in the Enduring Regime consultation, for Pathways to 2030 it is very important that deliverability of the 40GW by 2030 target (delivered consistently over the 2020s) is the key focus, and therefore all models should be assessed for their credibility with regards to the risk of delays. Models which present undue risk should not be pursued in this workstream.

It is important that the outcome of the Holistic Network Design ("HND") process is also taken into account when assessing the "right" party to undertake DND for assets in offshore waters. Dependent upon the complexity of the recommended coordination/integration between projects – especially projects of different asset classes – the most appropriate party to undertake offshore DND may vary. For example, where a TO-owned HVDC bootstrap is involved then the relevant TO may be the most appropriate. This would not necessarily be the case where two wind farms are integrating their offshore assets.

As highlighted in the HND section, the party that delivers the offshore (and associated onshore) DND needs to be correctly incentivised to deliver the most optimal design, balancing technology maturity, planning risk, cost reduction and environmental constraints.

Question 11: Do you agree that the existing developer led model should be retained and applied where the HND indicates a radial solution should be used? Please explain your answer.

Yes. We agree with Ofgem's proposal in Paragraph 3.35 that where the HND indicates a radial solution as being the most economic and efficient solution[1] the existing developer-led model should be retained, and for offshore zones where one developer is delivering all of the coordinating/integrating project portfolio (also see Option 6 below in our answer to Question 12).

[1] Please see our answer to Question 5 under the heading "Ofgem cost assessments & approvals" for our thoughts on what "economic and efficient" should refer to in the context of these OTNR workstreams.

However, we disagree with Ofgem's statement at the same paragraph that "*we do not think there is a need to change it [the OFTO regime]*". The issues highlighted to Ofgem by OWIC in their 2019 paper[2] on "short-term changes to the OFTO regime" have not yet all been addressed, and will not be as part of the scope of OTNR. We refer in particular to issues regarding fair allocation of risk and asset health for transmission assets.

Question 12: Please provide your views on each of the delivery options we have described in this document. In providing your views, please comment on the issues we have raised. Please also give your views on the implementation issues we have raised.

RWE believes that Ofgem should not select one option from the delivery models set out and further develop only that model at this stage. The outcome of the HND (including the outcome of ScotWind) must be known before preferred delivery models for each offshore zone can be identified. It is highly unlikely that a one-size-fits-all approach will prevail. The appropriate delivery models for each offshore zone will be dependent upon the levels of coordination/integration that can be realistically delivered whilst also hitting the 40GW by 2030 target for GB and 11GW by 2030 target in Scotland, via a steady pipeline throughout the 2020s.

Therefore we suggest that Ofgem proceed with further development of all credible models to deliver the 2030 targets. The chosen delivery models must therefore facilitate suitably experienced parties to move forward quickly and effectively without any delays which could otherwise be avoided.

The Leasing Round 4 offshore wind projects are already known and developers are already working on delivering those projects, including under the existing regime what could be coordinated connections to shore where multiple projects are being delivered by one developer. Certainty in the frameworks and regimes that these projects will be brought forward under is needed urgently, and time is of the essence.

ScotWind is very important to delivery of the 2030 targets and ScotWind projects will shortly also become known, with developers wishing to progress those projects urgently.

In both leasing rounds, developers have already made significant resource investments in moving projects forward and many already have signed connection agreements with NGESO. See also our response to Question 4.

In the current frameworks the incumbent TOs are not sufficiently incentivised to progress timely delivery of consents for network reinforcements. These parties are not exposed to liquidated damages, for example, to ensure that connections are consented and approved on time for individual connections. This is in contrast to developers, who are strongly incentivised to deliver consents for all the necessary onshore and offshore transmission infrastructure which forms the OFTO assets, because they bear very material commercial consequences to the overall project if there is delay. Whatever

[2] OWIC | Documents "Transmission Review Short-Term Solutions"

models are taken forward must seek to address this issue as part of accelerating delivery and improving efficiency of outcomes for consumers.

Delayed connection dates would expose developers to increased financial costs and risk. Specifically, the developers can be exposed to further option payments under TCE R4 or ScotWind Options for Lease, and also to late delivery penalties under the CfD and there may be penalties under commercial offtake contracts too. Where protections are not provided commercially then it may be necessary for the Government (or its agents) to provide those protections or mitigations instead.

We set out our thoughts and observations on each of the Options here:

<u>Option 1 - TO Build & Operate</u>

This delivery model is broadly analogous to that which is in use in other markets such as France and Germany to overall good effect, albeit in entirely different regulatory frameworks to GB. In other markets there are clear delivery milestones defined for both developer and TO, with the developer providing liability support for the earlier milestones. At the final delivery milestone, i.e. connection, the TO becomes liable for lost generation up to a defined level. In the GB regulatory model these protections do not exist, and this represents an issue of incentives and developer confidence that the delivery of grid would be on time. This latter point is exactly why the OFTO-build model has never been used in the current offshore regulatory regime, and developer-build has always been favoured. If this model is to be further developed this needs to be addressed.

We agree with Section 3.64 of the consultation that the onshore TOs do not have significant experience in delivering offshore infrastructure but do have some. To date only two TO owned offshore infrastructures have been delivered, i.e. Caithness-Moray HVDC and the Western Link HVDC although other similar links are in development phases.

RWE does not agree that this delivery model has the potential to speed up the process. The TOs have not demonstrated speed in the two examples above, and there is a lack of financial incentive for TOs to deliver grid on time. In the current developer-led model for delivery of offshore transmission the incentive on the developer to deliver robust assets on time is the imperative for a connection to export power from the generation assets. This dynamic doesn't exist for the TOs, as noted above, and whilst Liquidated Damages provisions in connection agreements exist for onshore and offshore infrastructure the value is set at £0.

In our view, Option 1 is inconsistent with the existing regulatory requirements and thus regulatory amendment would be required before it could be pursued. Section 6C of the Electricity Act 1989 provides that "offshore transmission" means the transmission within an area of offshore waters of electricity generated by a generating station in such an area. To provide offshore transmission an offshore transmission licence is required (or an exemption to this). Pursuant to section 6C(1) the Authority makes regulations to determine, on a competitive basis, the person/organisation to whom an offshore transmission licence is to be granted. The TO would need to be granted an Offshore Transmission Licence to transmit electricity generated in offshore waters as is proposed in this scenario. However, the option is inconsistent with the legislative requirements as the licence would not be determined on a competitive basis. Therefore legislative changes would be needed if this option is to be pursued. Where this model is further developed then the deliverability of such a change must be factored in to the risk of pursuing such delivery model.

As discussed in our answers to Early Opportunities, a TO-build approach might be the most appropriate for delivering offshore wind connections into a TO-owned HVDC bootstrap by 2030.

We would support Option 1 being further explored as part of the Enduring Regime.

Option 2 – TO Build > OFTO Operate

This model avoids the issues with Section 6C of the Electricity Act 1989 that Option 1 has. However, it is neither generator-build, nor OFTO build and so we consider amendments will be needed to the Tender Regulations.

In addition, this model utilises the Late Competition model, which is already used and well-understood. However it is unclear that there is an incentive for the incumbent TOs to design and construct an asset that they will not be permitted to operate, despite unbundling rules allowing this.

Potential complexities arise from incentivising TOs to deliver infrastructure on time (as with Option 1), and regarding cost control/assessment processes. This is discussed further in the "Charging & Code Changes" section below.

If this model is to be developed further there is a need to consider that TOs might not consider the grid asset holistically if they do not face any costs of ongoing operation (in the developed-build OFTO regime developers face these costs via Local TNUoS, and bear the risk of disallowed costs in the Ofgem OFTO cost assessment process). Clear incentives need to be in place to ensure that the design and construction is also optimised from an O&M perspective.

Option 3 – TO Design > OFTO Build & Operate

Many of the items raised above for Option 2 also apply here in a broadly similar form.

Any model in which an OFTO's responsibilities move away purely from ownership and operational phase represent a huge shift in what the market understand OFTOs to be.

This introduces fundamental risk as it appears that the incumbent OFTOs lack the necessary offshore construction experience to undertake such activities, and therefore new OFTO bidders with relevant experience would need to come forward. This could attract experienced TOs from the domestic and other markets, which may be good for competition but is fundamentally very risky to attempt delivery of this by 2030, whilst also delivering 40GW by 2030 in a steady pipeline over the 2020s.

Additionally, it doesn't appear to make commercial sense for a party to construct and operate assets it has not designed and optimised in the way this model suggests. For example, would the TO or OFTO undertake procurement activities? If the former then how would this impact cost assessment processes?

This would highly likely introduce delays. The incoming OFTO would also certainly take time to review in detail any designs before committing to build (and/or participate in tendering), possibly even choosing to make changes, thus this model does not accelerate programme.

We note that compared to Option 2, in this delivery model OFTOs would be better incentivised to deliver assets that de-risk their long-term stable returns, meaning that construction delivery and quality will be within their interest. In this model OFTOs should be incentivised to deliver the construction programme on time, as incentives and their revenue model should also be linked to achieved connection dates. This does not outweigh the significant deliverability risk identified above.

<u>Option 4 – Early OFTO Competition</u>

For Options 4 and 5 it is unclear exactly what the scope of the work would be. Would an OFTO be appointed to an offshore zone to deliver project connections grouped together? This question can only be answered theoretically at the moment, until the outcome of the ScotWind Leasing Round is known, and the Holistic Network Design is complete.

Further to our thoughts on Option 3; we agree with Ofgem's concern at Paragraph 3.59 that there may be difficulties for OFTOs to consent an asset that was designed by another party. As design also impacts on costs, it is unreasonable for an OFTO to bear any disallowance in the cost assessment process that is deemed inefficient as a result of design features.

Both Options 4 and 5 will require OFTO tendering after the HND is completed by NGESO. At this point, and during the OFTO tender processes, there will be no party progressing the design and consents of the offshore transmission works until an OFTO has been appointed.

Additional significant delays could be introduced by separating out the DND from the consenting activities. In our answer to Question 10 we highlight that offshore DND and pre-construction phase works are largely undertaken jointly by developers, as a way of maximising project optimisation. Onshore DND and consenting also benefits from this. This delivery model would significantly limit this, likely creating delays and inefficiencies.

Ofgem sets out that it considers there to be scope for benefits in design and construction from innovation from the Early Competition model – but acknowledges that delivery of these benefits would be limited by the detailed design work undertaken by the ESO/TO prior to the OFTO coming in. As with the current OFTO regime rules, innovation can also be thwarted because of the uncertainty of the cost assessment process. Developers are often put-off innovation by the uncertainty associated with cost-recovery processes and the pressures from CfD bid preparation to keep costs known and as low as possible.

In addition, as it is unclear what entities would be likely to come forward as OFTOs in this Option it is therefore difficult to say if innovation is likely.

<u>Option 5 – Very Early OFTO Competition</u>

In our view Option 5 is very similar to Option 4, and therefore our observations on both Options broadly apply to both.

Both Options 4 and 5 will require OFTO tendering after the HND is completed by NGESO. At this point, and during the OFTO tender processes, there will be no party progressing the design and consents of the offshore transmission works until an OFTO has been appointed.

As Ofgem appreciates, OFTO tendering processes can take up to two years (more than 20% of our available time to 2030). This model would be more complex than OFTO sales we're used to and therefore tendering could take longer. Therefore, if a model with an OFTO is used, it is essential that the point at which OFTO tendering is undertaken can be run in parallel with ongoing design, consenting and construction so as to not introduce any unnecessary delay – this seems extremely challenging for Option 5. Models that effectively pause delivery while OFTO tendering and appointment are undertaken would introduce significant risk to achieving the government's 40GW by 2030 target via a steady pipeline during the 2020s.

Option 5 may be the most appropriate means to deliver some of the 'wider' shared offshore transmission infrastructure in the longer term (post-2030) as more time will be available to develop the correct incentives and framework for such a model. This option should therefore be taken through for consideration in the Enduring Regime.

As highlighted elsewhere in our answers, the current lack of experience of the incumbent OFTOs in designing, consenting and building offshore transmission – and the uncertainty regarding which entities could come forward as candidates for OFTOs which are businesses designed for this purpose – undermine the deliverability of Options 3, 4 and 5 in particular.

Option 6 – Generator Build

This is analogous to the generator-build option used to date in the current OFTO regime. Amendments to this regime for enabling electrical integration of transmission infrastructure for more than one generator (potentially also including interconnectors) is being considered in the Early Opportunities workstream. We have expressed our thoughts on the challenges and opportunities in this context in our answers to the Early Opportunities questions.

This delivery model could require the offshore generator to oversee the development and construction of assets beyond those required for the first offshore wind farm – or even permit another offshore generator to deliver crucial transmission assets on their behalf. The lack of commercial incentive to take on the risks associated with this are discussed in our answers to the questions in the Early Opportunities section of this response, and in Appendix 1.

An advantage of this model regarding deliverability is that established offshore wind developers are the most experienced and best-resourced entities within the current market to undertake the necessary work, and there are no delays through DND or OFTO tendering as compared with the other models.

Allocation of risk and indemnities

In relation to all Options (other than option 6); where known defects are identified in the transmission assets constructed by a party other than the generator, what indemnification will the generator get from the TO or OFTO when those defects cause unplanned outages or require outages for repair? In the developer-build model, developers are required to indemnify OFTOs for patent defects on the basis that they have constructed the assets and the impact on the generator is considered a product of its own making. However, where the generator has not constructed the assets it should not be penalised as a result of the construction defects of a third party i.e. it should have the right for uninterrupted availability to transmit its power, equivalent to the access rights of transmission onshore generators.

In both Options 2 and 3, will the TO indemnify the OFTO for defects in the asset and underwrite the construction risk where the OFTO is unable to get insurance on certain transmission assets? How will the generator be covered for outages arising from patent defects that arose in the construction phase? Ofgem's policy in this regard is that risk should sit with the party best able to manage it: in these scenarios the generator has no say over design, construction or operation – and therefore cannot manage this risk?.

In Option 6, would the developer of the assets be held liable for any patent defects arising on the parts of the transmission system the developer constructed that service other wind farms? What about the parts which service multiple wind farms?

RWE

Charging & other Code Changes

We agree with Ofgem that more fundamental modifications to charging arrangements are likely to be needed for some Pathways to 2030 concepts. We also comment here on cost assessment processes.

For Options 1 and 2, for example, there are new challenges regarding cost assessment – and how that feeds into the charges generators face for the OFTO or TO owned offshore local transmission assets. The incumbent TO costs are assessed via Price Control processes – and usually set ex ante. Costs incurred by developers in the developer-build OFTO model are cost-assessed ex-post, usually with a proportion of costs disallowed. The disallowed costs are not recoverable by the developer. Would a OFTO or TO's costs for offshore assets (and therefore the TNUoS associated with this cost) be subject to ex-post cost assessment in any of the Options?

The TNUoS charging methodologies for local circuit and substation assets are very different for onshore and offshore assets (analogous here to TO-built or developer-built offshore assets). Any such difference in treatment for assets offshore but considered under different models different treatment for like assets in like conditions for no apparent reason is unacceptable. What would the TNUoS charging methodology be for OFTO-built offshore shared assets?

Our concerns regarding speed of delivery of changes to Codes – including those for charging – as previously set out in our answer to Question 7 equally apply in the Pathways to 2030 workstream as the government target is the same: 40GW by 2030.

Question 13: Please describe any feasible delivery options that we have not set out in this document.

A developer joint venture might be attractive where wider and shared transmission infrastructure is ultimately needed by a number of developers but no one developer wishes to take on the works in isolation. This could offer a developer led (Generator Build) route for delivery of all the necessary offshore transmission infrastructure with OFTOs being introduced at points of construction or operation. This is essentially option 6 with better potential to take on more of the necessary works.

MPI questions

Question 14: Do you think we are focusing on the right models at this stage, or are there other models we should be considering? Is it also necessary to consider the evolution of such MPIs from pre-existing assets? Ultimately, should Ofgem accommodate multiple MPI models (eg IC-led and OFTO-led) or just one? What factors influence your answer?

The models suggested seem sensible, although variations of these may arise in future. It is therefore important that enabling of MPIs is broad, and does not deliver only these two possible set-ups. RWE does not consider that MPIs would arise from pre-existing assets due to the technical need for electrical sharing of transmission assets to be planned from the early development phases of both generation and interconnector projects.

We consider that Ofgem should accommodate both interconnector-led ("IC-led") and OFTO-led models, particularly as in the Early Opportunities and Pathways to 2030 workstreams (as compared with the Enduring Regime) both are equally likely to be deliverable from a technical perspective as the other. The regulatory and market arrangements for each are very different.

The concept of energy islands also exists, and whilst we agree that IC-led or OFTO-led MPIs are likely to be frontrunners in terms of delivery, Ofgem should ensure that the regulatory and Code changes required to facilitate MPIs do not exclude potential future energy island concepts.

Question 15: Do you agree with this position with regard to ownership structures of MPIs under the current framework?

We agree with Ofgem's view that the collective effect of these provisions is that, under the current legal framework, an MPI would need to operate such that the different components of the MPI are owned and operated by different legal entities, each with its own licence – ie separate ownership of the OFTO, interconnector and generation assets.

We also agree that any significant development away from this model, for example with a single owner/operator of the transmission and interconnection assets, would likely require changes to primary legislation.

This represents significant complexity in the context of MPIs being realised in the 2020s, in particular via the IC-led MPI model. The lack of a stable regulatory framework for near-term development and long-term operational conditions of MPIs is currently undermining the business case for these types of assets. This is all very closely linked with the Trade & Cooperation Agreement ("TCA") between the UK and the European Union, and subsequently would require primary legislation to reduce complexities.

Whilst MPIs represent a more efficient use of transmission infrastructure as compared with a counterfactual of radially connected offshore wind farms in the same geographic area as interconnectors, these assets cannot be realised in any significant volumes until the regulatory landscape is clearer.

Question 16: What are the commercial, operational and regulatory factors that would drive a developers preference for either the OFTO-led or IC-led MPI model? and do you envisage a different usage of the component assets of an MPI depending on the MPI model?

In order for MPIs to be realised there are two overarching commercial conditions that must be met:

1. There is a need for a viable commercial model for interconnector developers to see a return on their investment which is on a level playing field with or better than investing in a standard interconnector.

2. There is a need for a viable commercial model for an offshore wind farm developer utilising an MPI connection which is on a level playing field with or better than a non-MPI or radial connection.

This refers not only to development and construction risk, but also to the commercial framework that governs the operational life of the asset(s). There is also an overarching technical need for a robust definition in legislation in order for different jurisdictions to produce compatible infrastructure.

In an OFTO-led model, where the connection point into the domestic GB network is effectively at the OFTO-owned offshore substation platform into which both the interconnector and offshore wind generator connect, the regulatory frameworks governing GB market design will broadly operate as today. There is a need to consider the network charging arrangements where the OFTO asset is essentially of shared use between the separate interconnector and generation entities. See also our response to Question 17.

In an IC-led model it becomes much more complex. Coordination between two territories' regulatory provisions will be needed, which adds significant complexity where generation exports are involved. See our response to "BEIS Question 1" below.

Question 17: How would the line to shore (L1) be used in practice and what would you consider to be the primary and secondary activities from a practical perspective? Please provide views for both the IC-led and OFTO-led models, highlighting any differences between L1 usages across the two models.

In a situation where the technical parameters of L1, L2 and the offshore wind farm are identical, we would expect that in an OFTO-led model, the offshore generated electricity will be prioritized over cross-zonal flows on L1, making the offshore generation exports to the GB shore the primary activity. We therefore agree with Ofgem's findings from early engagement with developers in paragraph 4.43 that that the commercial viability of MPI projects is underpinned by the requirement to provide priority access to the offshore wind element of the project.

Here we understand "priority access" to mean the right to bid for low carbon support on a level playing field with "standard" offshore projects. This will also mean having the same access to mechanisms that compensate generators for being constrained off.

Priority access should also mean the generator is not subject to short term market congestion rents based on price differentials between interconnected markets, as these can be highly volatile and unpredictable and are likely to significantly increase risk capital costs for renewables investments.

In an IC-led model, offshore generation could have to compete with cross-zonal flows via market mechanisms on L1, meaning that the market constantly (re-)decides the primary and secondary activity.

Question 18: Are there any barriers within the current frameworks, such as definitions within the CUSC, SQSS or other industry codes, that might prevent the line to shore (L1) being classified as either an OFTO or an interconnector while undertaking other secondary activities?

The definition of an Interconnector within the BSC and CUSC is "Apparatus, connected to a System, for the transfer of electricity to or from the Total System from or to an External System".

The Total System includes offshore wind assets connected to the NETs via an OFTO. It is therefore likely to be more complex to legislate and codify a home market solution where the line to shore is defined as an interconnector rather than an OFTO.

Question 19: What are your views on the feasibility of adopting a regime that requires developers to submit evidence to support their licence application (for assets that form part of an MPI) and commit to regular performance reports? Would this be practicable, proportionate, and effective? Are there other options that work well for industry that we could explore further?

Offshore wind developers would presumably only ever assume the generator licence and we see no necessary changes to this one license over time that would require regular reports to re-assess said license.

In keeping with statements above, operators of MPIs that are primarily for the export of power from an offshore windfarm should be exposed to the same reporting requirements as OFTOs operating a standard radial connection. MPIs that operate primarily as interconnectors should face the same reporting requirements as "standard" interconnector licensees. To do otherwise risks creating an uneven playing field between operators of MPIs and their more "traditional" counterparts.

Question 20: What are your views on the practicality of transposing obligations from one licence into another, which obligations would be the most important to incorporate into a remaining licence?

Question 21: Do you think the exemption provision with the Act offers any solutions to licencing MPIs within the current framework, even if only a temporary solution until a potential enduring solution is implemented?

Question 22: Are there any aspects of the priority dispatch and curtailment arrangements, the TCA, or the cross-border trading arrangements that are adopted in UK that might influence the choice of MPI models?

Please see our response to BEIS Question 1.

BEIS Question 1: What do you consider to be the key challenges to the establishment and operation of MPIs in the UK presented by current and proposed regulatory requirements applicable in EU Member States or other countries which MPI projects may connect with, or by the TCA? (eg regarding the efficient operation of MPIs under both the Home Market and Offshore Bidding Zone approaches). Are there further domestic challenges to these possible market design options?

For the future development of MPIs it will be key for GB and the EU to align (or at least consider how their respective regimes can cooperate) on their developments for MPIs (which the EU calls hybrid projects).

The EUCOM considers that connecting European markets with interconnectors (and offshore wind farms) will be necessary for the efficient and future-proof build-out of offshore wind. Further EU-proposals are expected towards 2022.

Currently, the main issue on EU-level associated with cross-border trade of interconnectors under a "Home-Market set-up"; (meaning the offshore project is associated with a national or home market), is the so-called 70% rule. This rule requires that an interconnector needs to "reserve" 70% of its capacity for cross border trade. This means that this capacity cannot be "reserved" for an offshore wind project that is connected via the interconnector. Furthermore, the remaining 30% would also not be physically available to the windfarm as the interconnector needs to reserve capacities for balancing and other measures. Substantially oversizing the cable is therefore no real option. There have been derogations granted against this rule (Kriegers-Flak Project), however, only on a 10 year time-limited basis, which is not an acceptable or feasible level of regulatory certainty for an offshore project that has at least a 25 year lifetime.

However, this "70% rule", only applies to interconnections within the EU's internal energy market. The TCA provisions would govern any MPI between the UK and a third country. Therefore, efforts should be made by both GB, EU and third countries in the internal energy market to harmonise or align any future regulations.

Therefore, the EU Commission has now started promoting the "Offshore Bidding Zone" concept, which will set up a remote market that isn't connected to any national electricity market. The issue associated with this approach is that the market price of the offshore bidding zone will always be the one of that of the cheapest connected market (via interconnector), meaning the offshore windfarm will consistently receive the lower of the two market prices. The cross border trade, however, will go towards the market with the highest price. In order for offshore projects to become economically feasible in this set-up, a revenue-sharing mechanism still needs to be established. Any revenue support mechanism which is linked to the wholesale price in only one of the interconnected markets will result in under-remuneration for the offshore wind farm whenever the power is flowing to another, lower-priced, market.

Ultimately, MPIs are only going to become reality if a business case can be created for the developer and TSO or/and OFTO that is at least on par with a radially connected solution. Regulatory enablers or a framework are still due to be developed. Further work in both the EU and GB is needed to develop a suitable framework for the treatment of UK-EU MPIs to ensure that the capacity is developed and allocated efficiently between the dual purposes.

Appendix 1: Letter from OWIC to Ofgem and BEIS regarding commercial incentives

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To:
Rebecca Barnett, Deputy Director, Deputy Director, Commercial & Assurance, Ofgem
Chris Fox, Head of Europe & Offshore, BEIS

27th November 2020

Dear Rebecca and Chris

The Offshore Transmission Network Review is a welcome development to progress the transition from the predominance of point to point connections to a more coordinated and eventually integrated grid solution. The offshore wind industry supports a wide and ambitious multi-stakeholder review of the offshore wind transmission regime, including regulations, frameworks, technical standards and commercial arrangements.

The commitment to deliver 40GW of offshore wind by 2030 and the need to reach net zero means that offshore wind development will accelerate. It is important that we have the offshore and onshore infrastructure in place to deliver this low-cost renewable electricity to people's homes and businesses. We believe that the future transmission framework for offshore wind needs to ensure that it that considers the needs of coastal communities, while effectively balancing s social and economic costs and deliver for the UK bill payer and environment..

The offshore wind industry recognises that the existing regime for offshore transmission, which incentivises radial, point-to-point connections, needs to evolve. However, the timing of evolution and impact on project development cycles – and in consequence the 40GW by 2030 target - is an important factor to consider.

In order to evolve the offshore transmission framework, assess the risk and reward profiles and put in place the mechanisms needed to deliver a more coordinated and eventually integrated grid, it is essential that government, industry and other stakeholders understand and address the regulatory and commercial barriers.

In the joint BEIS and Ofgem open letter, *Increasing the level of coordination in offshore electricity infrastructure, 24 August 2020*[3]*,* BEIS and Ofgem requested an assessment of barriers facing greater coordinated transmission.

> *A key step in the review is for us to understand what has stopped the development of coordinated transmission assets to date, and we welcome suggestions on how barriers could*

3 https://www.ofgem.gov.uk/system/files/docs/2020/08/increasing_the_level_of_coordination_in_offshore_electricity_infrastructure.pdf

be overcome. We would like to hear about all potential barriers, including those of a legal, commercial or regulatory nature. As the economic regulator, Ofgem would also like to understand where a change in current regulatory arrangements now could facilitate greater coordination or if wider change is needed.

In response to this request, and in order to help to shape the required solution, OWIC has been working to identify the commercial risks we see to increasingly coordinated connections for offshore wind, where these fit in the project cycle and how they could be addressed.

We anticipate that establishing the enduring solution will be a complex process with many issues to resolve, therefore transitional arrangements will be required to ensure progress is made in the short-medium term. It is important to keep at the front of our minds the purpose of the Review: to deliver 40GW of offshore wind by 2030 and enough to meet our net zero ambition by 2050, which the Committee on Climate Change have said could be more than 75GW.

OWIC see that there is a need to evolve from how projects are incentivised to connect in the current regime (radial, sole-use assets) through to integrated offshore grid infrastructure (post-2030) without creating delays to projects already in motion, and without risking the government's 40GW by 2030 target. This evolution will rely upon first incentivising increased coordination between projects (both generation and potentially interconnection) in the "medium term" (2025-2030) on an opt-in basis. OWIC's assessment of key barriers to increased coordination in the medium term can be found in Annex 1 below. The "enduring solution", post 2030, is likely to include a mixture of sole-use, radial assets as well as increasingly coordinated and integrated grid.

Ultimately, multi-billion-pound offshore wind projects are reliant on secure and de-risked grid connections, they are dependent on the developer's ability to manage project risks and they require significant low-cost capital. The development of a more coordinated and ultimately integrated offshore grid, which is likely to involve shared connections, needs to ensure that the risks are minimised and allocated to the parties best able to deal to them. The grid risks need to be in step with the wider project delivery risks and not hold up decision gates through the development process. Grid is the critical-path programme driver for many offshore wind farms and likely that all projects on track to deliver by 2030 will be extremely sensitive to any changes in the grid connection process. Both increased coordination and the enduring solution (as described above) must enable a number of commercial parties, the ESO, TOs and governmental organisations to work together to deliver such a model whilst not undermining investment in the sector.

Developing and constructing the grid connection is one of the longest lead items when delivering an offshore wind farm. Generally, projects in late stage development would have already taken significant steps to de-risk the connection. This will typically include:

- going through the ESO's CION process to select the most appropriate connection point
- entering into a connection agreement and securing liabilities under that connection agreement
- undertaking extensive onshore and offshore surveys
- obtaining consents/planning permissions for onshore and offshore works
- conducting detailed technical design work
- completing considerable stakeholder engagement
- purchasing or agreeing access rights to land for the cable route and onshore substation
- engaging with suppliers and optimising the project based on the contracted grid position

It will often also include progression of local or wider network reinforcement works by the relevant TO in advance of the connection, some of which may be financially secured by the developer. Lastly but importantly, projects may have used or be planning to use their existing grid connection agreement as the basis to be eligible to participate in a Contracts for Difference allocation round. Arrangements for increased coordination and the enduring solution, including delivery of a more integrated offshore transmission network must recognise the importance of all of the above aspects of offshore wind project development, and provide adequate risk mitigation.

Throughout the design, consenting, development and construction processes there are a number of milestones that need to be met and decisions that need to be taken in order to facilitate continued investment in an offshore wind farm project. As described, in the transition to an enduring solution with a more integrated offshore transmission network, it is likely that coordinated connections will feature in some areas of the country. To deliver this approach the risks at each of these milestones needs to be understood, and the risk/reward framework assessed from a regulatory, engineering and commercial perspective. This includes who will bear the risk and how it will be mitigated. For example, if two wind farms intend to utilise a shared connection, it needs to be clear who designs, plans, consents and builds the connection and how they accommodate for different project designs, delivery schedules and approaches, bearing in mind that in the current CfD model projects sharing the connection could be competitors in an auction. There also needs to be a framework to manage changes in wider project schedules or designs and the review needs to consider the impact if one or more of the wind farms sharing the connection does not go ahead.

Considering the significant cost associated with delivering larger shared transmission solutions, it may not be feasible for an individual project to take the risk of being materially exposed to the cost of a competitor choosing not to progress its project.

Attached to this letter (Annex 1) is a summary of the commercial, regulatory and design risks that OWIC members have identified when considering the process of development and delivery of shared connections. For these purposes it assumes two offshore wind farms sharing a single connection, but many of these issues will be faced for more complex designs, including wider offshore integration.

As a follow up to this analysis it would be useful to identify the lead party or parties who could be responsible for managing these risks, for example, BEIS, Ofgem, the ESO, TCE or CES, Transmission Owner(s) or the project developers. We believe, it is important that these parties consider these risks and the approach to managing them for the OTNR to be a success.

We are of course, very happy to have any further discussions on any of these issues, if that would be helpful.

Yours sincerely

Zoe Keeton

Workstream Lead, Offshore Transmission

Offshore Wind Industry Council

Appendix – Key commercial considerations for greater offshore connection coordination		
Phase	**Question**	**Commentary/Consideration**
Inception	For future offshore wind site leasing rounds, how does the leasing process interact with the grid connection process?	The current approach incentivises developers to move quickly to secure a grid connection on a sole, radial connection basis, sometimes even before leasing round results are announced.
Inception	For future offshore wind site leasing rounds, how does the leasing process interact with the identification of strategic onshore infrastructure locations?	In the immediate term The Crown Estate and the Crown Estate Scotland should work with the ESO and TOs to identify onshore network constraints, and feed in to planning processes such as the NOA and ETYS. This should be facilitated by obligations and incentives upon the ESO and TOs during the RIIO-2 price control. Due to the annual cycle of ETYS and NOA it is essential that the relevant obligation and incentives are applied as soon as possible in 2021, if not included in the Final Determinations. This will mean that more preparatory work will need to take place before firm commitments are given by generators.
Inception	If two offshore wind projects have been identified as having potential for a shared connection, how do you determine how ownership should be arranged between the projects for the shared connection?	
Inception	Who “holds” the TEC?	It would be very problematic for one developer to hold all of it. For example, the second developer wouldn’t have a grid connection and therefore couldn’t bid at CfD auction, or if one developer has the power to change the connection dates or capacity

		If there are separate connection agreements where is the offshore transmission development scope fully captured? For MPIs what is the TEC technology type?
Inception	From the outset there may be commitments towards NGESO and associated cancellation/delay liabilities (in respect to onshore TO development activities). How are these apportioned between two projects?	It is not reasonable to expect one project to cover all commitments/liabilities for a project encompassing more than that one project's needs.
Development	How do the projects define initial development parameters such as consent envelopes and ecology survey areas while ensuring adequate coverage for both projects?	This is complicated if projects have different views on consent risk or optimal solution, where one project may favour a different technology, onshore cable route, offshore cable route and general approach (including associated cost) to get to consent. This could become especially challenging if consenting coordinated connections where landing points and cable corridors (although reduced in number) may increase in size to accommodate multiple projects.
Development	How is the second developer included in stakeholder engagement?	At present a significant part of the development process is articulating to stakeholders (including the general public) what the transmission assets are for. As a specific example, acquiring onshore land or agreeing access rights, and onshore planning typically involves providing information on the offshore projects and their technical parameters, timescales, identities, etc.
Development	How are development costs covered until the OFTO transfer? Under the current framework the first project developer may cover these, however coordinated development costs will be far higher than for an individual point to point connection.	This is likely to be a larger issue for development than construction, as for construction the OFTO assets can be debt financed with high gearing (and the developer earns IDC), whereas during development phase the project is carrying the risk. However, views across projects and developers could differ on these points.

Design	How does the first project incorporate technical input from the second project (e.g. project capacity/configuration/technology choice) while recognising commercial sensitivity?	At present, regardless of contracted TEC, project developers can, and regularly do, flex their transmission asset concepts to reflect project strategy (e.g. CfD bidding strategy or wider project changes) but doing this in an integrated context would require disclosure to a potential competitor.
Design	Even if the commercial sensitivity aspect can be overcome, how is the design process coordinated if the first and second projects are on different timescales, or if these timescale diverge during the development phase?	This can be material to electrical design inputs, for example the later project may want to await/access further WTG technology development.
Design	In addition, it is very common for projects to change the grid connection sizing or timescales as they advance and refine the offshore wind project, which currently involves the ESO. Factors behind this include changes in WTG technology as project's develop (a key cost of energy driver) and enhanced understanding of the offshore wind farm site and its optimal capacity/configuration. How would this be controlled and managed in an coordinated approach?	It's important to avoid lock in as projects change significantly during the development cycle.
Design	How are substantive design decisions controlled ensuring coordination between the projects, NGESO, TOs?	At the moment individual projects have relative freedom when following generator build for sole-use transmission assets (NGESO and ultimately the appointed OFTO are informed largely after the event what the design looks like).
Financing	How do projects show their funders (at the point of investment decision/financial close) that their long term liabilities for the transmission assets related to each	

	project are sufficiently "ring fenced", e.g. in relation to cost recovery, long term charging liabilities or OFTO indemnities (see below).	
Financing	How do projects provide certainty to their funders on the availability of the connection if they do not directly control the programme, and, particularly early on in the development process, their agreed connection date is potentially subject to a needs case involving other projects?	At present lenders and insurers take significant comfort from the fact that the OFTO and wind farm assets are designed and developed in the same programme with the same sole aims.
Construction	In the event that the coordinating offshore wind projects have reasonably closely aligned programmes (which is possible), how are commissioning programmes and outages coordinated to avoid excessive delay/impact to each project, and how does this interact with the OFTO divestment programme?	On the face of it this should be possible to coordinate with close cooperation, however lenders and insurers will want a clear position and operational impacts/risks (e.g. availability and outage treatment) should be considered.
Construction	How does the grid code compliance process work at each stage?	The process of demonstrating grid code compliance for a large generation project is complex and lengthy, but at present is fairly well understood by developers and the supply chain which provides important certainty in design and construction phases. Integrated offshore transmission will introduce new technology and connection boundary arrangements which are likely to materially impact on the compliance process and this is an area which will thus require considerable attention.
OFTO transfer	*This is an area that needs to be considered in detail, so the list below should be viewed as illustrative and non-exhaustive.*	It is important to recognise the features of the OFTO regime as it presently stands which facilitate access to low cost capital, so as to ensure that access is not undermined.

	Would the projects be expected to provide the same sort of warranties/indemnities toward the OFTO that projects (under current generator build arrangements) are required to? This would be a big ask, as one project is effectively then the insurer of last resort for a connection asset which it is only partially using. How would cost allowance be treated across assets? How would the divestment process work if part of the connection for another project is still being built? How would the generator commissioning clause operate?	That access exists not only via the funding of the OFTO entity, but when the construction of the transmission assets is initially funded by the offshore wind project. The regulated nature of the assets and the level of confidence that is provided on cost recovery and charging are material factors in enabling high gearing and low cost of debt if the construction is being debt financed.
Operations	In the event of maintenance/failure events requiring curtailment of generation, how is this apportioned between the projects?	At present the generator is not kept whole for the loss of availability (i.e. the OFTO/NGESO do not compensate the generator) therefore it is a commercially significant point. Again, as above this will be material to funders and insurers.
Operations	How will network use of system charging be structured and administrated?	This is an area of primary importance which will require clear, early guidance if pursuit of shared connections is to be viable.
General	What right of visibility do projects have over each other’s activities?	If projects have interdependencies as a result of sharing a connection, they will need some level of visibility of each other’s progress to support decision-making on project development approach and investment.
General	What happens if the anticipated first project is delayed to the point that another project is anticipated to be constructed earlier?	This could happen for any number of reasons, e.g. technical challenges, change in strategic direction of the developer, failure to secure a route-to-market, funding.

General	What happens to the shared connection if one of the coordinating projects is abandoned at any point?	This will be material to the other projects' ability to make commitments to their project(s) through development phase. No project developer will spend tens of millions on developing a project if a third party has the ability to significantly impact delivery. A simple fallback where one of the / the only other coordinating project takes over the transmission asset development might not be sufficient as the transmission assets have been developed to share so will not be economic for one project only.
General	What happens if the one of the projects is abandoned at any point?	This could be a situation where two generators seek to coordinate connection assets and either projects is abandoned in early stages by its developer(s). This could be where the project seeking connection earliest pulls out, or the other way around.
General	How are the projects incentivised to achieve a design that is reasonably balanced from an economic and risk perspective for all the projects involved in the coordinated connection?	As a crude example, assuming a shared offshore connection point between offshore wind generators only the location of that offshore connection point relative to one or more wind farm sites connecting to it needs to be determined. This would equally apply to a Multi-Purpose Interconnector.
General	What happens if consent is not granted to one of the projects involved or for the onshore works?	