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Consultation on Offshore Transmission Network Review: proposals for an enduring regime and multi-purpose interconnectors

RenewableUK response

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About RenewableUK
RenewableUK's members are building our future energy system, powered by clean electricity. We bring them together to deliver that future faster; a future which is better for industry, billpayers, and the environment. We support over 400 member companies to ensure increasing amounts of renewable electricity are deployed across the UK and to access export markets all over the world. Our members are business leaders, technology innovators, and expert thinkers from right across industry.

Introduction

0.1. RenewableUK and our members welcome the opportunity to respond to the Offshore Transmission Network Review's second consultation on changes intended to bring about greater coordination in the development of offshore energy networks. Prior to the publication of the sector deal, we highlighted the need to move away from the current connection regime, which encourages point-to-point radial connections, to a more coordinated offshore network, we noted that the "future deployment of offshore generation will benefit from a more sophisticated, innovative offshore transmission network, which the OFTO regime we have today may not be able to support". Industry agrees with government that the current regime based solely on point-to-point connections is no longer fit for purpose. RenewableUK and OWIC have strongly supported the work from BEIS, the ESO and Ofgem to lead us to the OTNR review.

This is the ideal time for a significant overhaul of the way we plan, deliver and connect offshore wind projects after an evolutionary approach over the last two decade. A clear, simple and timely process that can help us achieve our net zero targets is required.

We answer consultation questions in detail below, but would also like to take the opportunity to make the following general points:

0.2. *The need to build on Ofgem's Early Opportunities and Pathways to 2030 (PW2030) work*: in July 2021, Ofgem consulted on Early Opportunity projects and projects to meet 2030 targets. Due to the stage of development of the Early Opportunity projects, this consultation sought views on how best to facilitate the projects and their various innovations through incremental code changes, regulatory flexibility and a more considered approach to anticipatory investment where the consumer might take more risk. The PW2030 consultation sought views on the holistic network design (HND) that is being developed to cover these projects, and the delivery models best suited to deliver the offshore transmission works required. The over-arching driver for both is delivery within short timelines.

0.3. In our response to Ofgem in relation to the Early Opportunity projects, RenewableUK agreed the consumer would need to take more risk and highlighted how the existing User Commitment (underwriting) framework, and transmission charging framework, could be used with some minor amendments to facilitate anticipatory investment for the early projects.

0.4. In our response to Ofgem in relation to the PW2030, RenewableUK agreed in broad terms with the HND approach and commented on the proposed delivery models. We highlighted that a **developer-led model** was best placed to deliver in the short timescales and that an OFTO could be introduced earlier in the process than at present, e.g. to construct and operate rather than just operate. We also highlighted this aspect of introducing an OFTO earlier than present in the TO-led models for offshore transmission delivery, noting in both cases this could provide a steppingstone for early OFTO delivery models in the Enduring Regime if those were seen as desirable. We believe a developer-led model will still have a role to play in an effective Enduring Regime.

0.5. Whilst we acknowledge BEIS's 'blank sheet' approach is appropriate, we believe that the Enduring Regime should use and build on the PW2030 work in providing the smoothest transition to an Enduring Regime. This is of course subject to the way forward being similar and a development of the PW2030 work.

0.6. Similarly, we believe the Enduring Regime should take forward amendments to anticipatory investment, potentially with some increase of consumer risk. The lack of a useable framework for this has been one of the barriers to coordination and integration. Amendments to User Commitment and transmission charging (and other codes) should be taken forward from the Early Opportunities projects and PW2030 projects into the Enduring Regime assuming they are fit for purpose and not wholly suited to a short-term rapid delivery for 2030.

0.7. The OTNR could take learnings from the UK gas system, which has successfully connected a number of projects to the main transmission system in a timely manner. Six coastal locations were chosen as hubs to provide high capacity access to the UK gas transmission system with all onshore works carried out by the equivalent of the ESO. While the engineering and security of supply standards are clearly very different for gas and electricity there are some parallels that could be drawn. For example, hubs could be suitable locations for any further interconnector capacity, and coastal bootstraps could be employed where needed to aid the general north-south energy flow.

Towards a strategic plan

Question 1: We think that a more strategic approach to the planning and development of offshore wind is needed to achieve the Review's objectives. Do you agree? Please explain your answer.

1.1. Yes, we agree that creating and implementing a strategic plan is required for the delivery of offshore wind and for achieving the objectives of the OTNR. A top-down model that plans out windfarm development further in advance can provide much needed stability and certainty for investors and developers, and will ensure that renewables are connected to the grid on time, which is vital for achieving the UK's net zero targets (e.g. 40GW of offshore wind by 2030[1], and approximately 100GW by 2050). Net zero needs to be achieved, but at lowest cost and in a way that takes into consideration consumers, society, and the environment. In other words, any plan should not only consider the baseline capital cost, but also long-term value, within the limited timeframe available. The Enduring Regime should consider a wider energy systems-based approach, considering the major changes to come, for instance around decarbonisation of heat and transport and the role of hydrogen, storage and flexibility assets. This can help to answer the question of how we will manage excess power on the system beyond 2030, as there may be large surpluses during periods of windy weather and low demand. It is not possible to strategically plan the grid network without understanding the location of future windfarms, so these elements need to be considered holistically.

1.2. The strategic plan will set out a vision focusing on the need for investment, and recommending how to satisfy the high-level needs of the GB transmission system (i.e. need to deliver a certain volume of capacity between point A and point B by a specific date). It should facilitate a net zero 'least worst regrets' investment plan for both onshore and offshore grid infrastructure. As stated in the consultation document, delivering the benefits of coordination in the absence of a strategic plan would be difficult and likely limited in scope.

1.3. When considering the strategic plan, there is the need to balance the acceleration of offshore wind deployment (that delivers best value for UK consumers) against environmental impacts and co-use, at sea and on land. A top-down model should focus on identifying tangible sites that deliver the levels on offshore wind investment required to meet the CCC's decarbonisation pathways. In some cases this may mean trade-offs between stakeholders, departments and financial interests, however we believe is it important that the strategic plan always reaches our net zero goals. We also believe that if this approach is taken then the strategic plan should have a formal role in the planning and consenting process, thereby de-risking future consents.

1.4. We agree with BEIS' view that:

"*it is unrealistic to expect changes to the latter stages of the windfarm development process to be able to deliver significant benefits if the early stage does not plan coordination. If the location and timing of generation development is not planned to maximise coordination, it becomes harder to achieve this later in the development process.'* and, *'if seabed leasing maximises opportunities for coordination, this could result in a smaller number of potential projects."*

We note that the overall objective should be based around the delivery of offshore wind at speed and best value for UK consumers, not coordination for coordination's sake. Therefore, we believe that coordination should only be planned (at the outset of project development) where it is the consumer's interest to do so, and where it makes economic or geographic sense radial development should continue.

1.5. Ofgem's remit will need to support these aims, but any mention of strategic net zero is currently lacking. We strongly support a statutory duty for Ofgem to deliver net zero emissions, that can be challenged in court if necessary. Amending Ofgem's remit is absolutely crucial to ensuring that decisions about network anticipatory investment, and delivering solutions which are sympathetic to environmental and local community needs, are able to be taken holistically. The net zero reopeners in RIIO-2 only go so

[1] *Net zero strategy: build back greener*, Dept. for BEIS, Oct 2021

far; there is a danger that the strategic plan identifies 'least worst regrets' for net zero recommendations for investment/scenario planning and Ofgem is unable to approve actions because its interpretation of its current remit is short-term cost savings rather than strategic delivery of net zero.

1.6. We recognise the concerns that stakeholders have about under- or over-sized investments due to strategic planning. Any plan for 2050 is subject to uncertainty, but a strategic plan should provide the high-level strategy for achieving net zero, which can be refined over time, leading to detailed transmission plans. This ensures that the strategy is robust against a range of scenarios. While it is inefficient to build more infrastructure than required, it would be reckless to only plan for a singular scenario with the minimum build-out of offshore transmission which ultimately leads to the UK missing out on our net zero target.

1.7. We note that the strategic plan will also "consider other uses of the marine environment, such as fishing, shipping, aggregates, oil and gas". This approach could help to balance co-use as the UK's seas become more congested. As the UK looks to decarbonise and deliver on its climate targets, we will need to phase out oil and gas and ramp up renewable generation. Therefore, a decarbonisation weighting towards low-carbon/renewable assets might be required in the plan. It is essential to ensure that the design and implementation of a more strategic approach does not in itself result in delays to offshore wind delivery due to the required levels of co-ordination and alignment between all parties involved. Therefore we recommend that input is sorted and assessed at an early stage.

Question 2: If you agree, do you have any views about the scope of the strategic plan? For example, should it cover generation or be limited to transmission?

2.1. The strategic plan must include in its scope generation (offshore wind sites), transmission and interconnection (including MPIs). It should identify specific areas for offshore wind development across multiple leasing rounds, both temporally and spatially, including interactions with the onshore system. In other words, it must be detailed enough to inform stakeholders about future locations of windfarms and grid configurations over a specific timeline. A whole-system approach will become increasingly important as the volume of offshore wind, storage and other energy vectors like hydrogen increase in the coming decades, if least regret solutions are to be found that will drive best value for the consumer. We broadly agree with the components of the strategic plan outlined in the consultation, however as mentioned in **Q1**, some of these elements may require a different weighting than others if we are to reach our decarbonisation targets and accelerate offshore deployment.

2.2. We also note that the strategic plan needs to be able to interface with the planning consent regime, on both a local and national level. Review of the National Policy Statements (NPS) should incorporate assumed consent for projects that fall within the strategic plan. The ability to consent major projects is a key area of risk for developers. The strategic plan should have a significant weighting in the planning process, especially where upfront work has been conducted to review environmental risk and community impact.

2.3. The strategic plan should take a top-down approach, where the capacities of offshore wind required to meet decarbonisation targets (based on CCC scenarios) are identified, as opposed to the current bottom-up process. This approach would identify where conflicts with other marine users may arise and provide a focus for seeking methods of co-existence or, where necessary, prioritisation. The top-down approach should follow the mitigation hierarchy; however it is not realistic to expect that all impacts can be avoided, and therefore mitigation and compensation may be required.

2.4. *Transmission system design from strategic planning*: In **Q6** to **8**, the consultation asks about the need for a Holistic Network Design (which we agree is necessary). However, to produce a forward looking HND requires visibility of offshore wind farm development. If the HND is to look ahead 10 or 15 years, then a view must be taken on offshore wind farm development to this time horizon. As noted by BEIS, it is possible to anticipate where developments might occur, but this could contain a high level of uncertainty. NGESO has already taken this approach in its Phase 1 work[2] to produce a high-level network design. There could be an opportunity for better coordination between the ESO and ongoing work by BEIS to map out and explore future offshore wind scenarios.

2.5. Were there a more strategic approach to offshore wind farm leasing and development with clearly identified areas, target volumes and target dates, then this better visibility would facilitate more certainty for developers and help with the development of the HND. This would reduce risk and cost and assist in developing and delivering infrastructure to minimise environmental and coastal community impacts. Clearly, the more detailed the strategic plan, the more detailed and certain the HND can be.

Question 3: What governance arrangements would be appropriate for a strategic plan? For example, who should be the lead organisation, and what roles and responsibilities would other partner organisations have?

3.1. The remit of the strategic planning body should be clear from the outset and BEIS should consider consulting on the terms of reference. We note that the strategic planning body needs suitable expertise, capacity to deliver, and the political clout to drive through reform. We recommend that the strategic planning body terms of reference are aligned to net zero delivery and linked to the legally binding carbon budget targets. We believe that further work might be needed to consider the most appropriate approach to strategic planning.

3.2. We believe that BEIS would be good choice for leading development of the strategic plan, which has both the authority and expertise required. Alongside the grid aspects of offshore transmission, the strategic plan will consider spatial offshore elements, including environmental impacts and co-use of the seabed. The strategic plan will impact on other parts of Government, such as Defra, MoD and DLUHC, and BEIS has the cross-departmental contacts necessary to facilitate cooperation and challenge other areas where required. Furthermore, decisions and compromises will be required to deliver our best value decarbonisation pathway, and the strategic planning body will therefore need the standing to discuss and challenge other Governmental departments. Work on the strategic plan must involve other key stakeholders, such as Ofgem, NGESO, Crown Estate (and CE Scotland), TOs and developers to provide essential knowledge and expertise. Support could come through an ENSG-style forum (see **Q4**) or a separate consultation process.

3.3. Alternatively, a well-funded and well-resourced future system operator (FSO) could do the role. This would require the FSO to look ahead of the energy planning system and take into account the energy system as a whole, which must include all the variables that a flexible and low-carbon energy system will need, something that we have not seen performed by NGESO so far. We would also expect the FSO to be innovative

[2] *Final Phase 1 report in our offshore coordination project*, National Grid ESO, 16 December 2020

and work in coordination with other parties across the energy system. An independent FSO would be subject to less political pressures than BEIS, however it is not yet clear exactly what powers/remit it would have, which adds risk and uncertainty.

3.4. It has been suggested that a new, independent energy agency (National Energy Agency)[3,4] would be a good alternative to lead the strategic plan. This could be an equivalent to the Oil and Gas Authority (OGA) but for renewables. However, adding yet another player into the already crowded space may only complicated matters further; if this approach was pursued, a clear delineation of duties would be required.

Question 4: How should stakeholders be consulted during the development of a strategic plan?

4.1. Stakeholders will be central to the development of a robust, deliverable, strategic plan, and they must be consulted regularly. Consultation should be focused on how to achieve the plan and stated offshore wind targets, rather than starting out by seeking to protect or carve out areas. By taking a top-down approach, consultation can be focused on identifying where co-existence may be most viable. We believe the consultees should be provided with adequate time to review and respond to a consultation, and the plan may need to go through more than one round of consultation as proposals are adapted. We believe that the delivery targets and decarbonisation pathway should be paramount and the volumes of offshore wind (fixed and floating) included in the plan should be enough to reach our net zero target. Where offshore wind areas are identified by a strategic plan but the location is considered by stakeholders as being unsuitable for development, these could then be reviewed on a case by case basis, rather that starting out with wide ranging constraints that then must be chipped-away to provide enough area for offshore wind.

4.2. At present, National Grid ESO publish a yearly NOA document, which provides signals for activity by the TOs and ESO for the year ahead. Projects that are already well advanced (such as wind farms after FID) are still reviewed annually to assess the appropriateness of continued construction. Therefore, the NOA methodology takes a power system approach to assessment, and does not factor in net zero targets and other stakeholder concerns. In addition, the inputs for the NOA change significantly year-on-year, resulting in a degree of unpredictability[5]. It also adds more uncertainty into the process of planning, consenting, and building new infrastructure and generation assets. A strategic plan must be less short-term and narrow in its approach.

4.3. Before 2017, GB network planning was pursued through the Electricity Network Strategy Group (ENSG)[6]. Jointly chaired by BEIS and Ofgem, the group took responsibility for agreeing a series of major network reinforcements based on independent technical, economic, and environmental analysis. A wide range of stakeholders (developers, OEMs, large energy consumers, local community representatives) were consulted in an open and transparent policy-led process. Returning to an ENSG-style group or forum could be a good fit for developing the strategic plan.

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[3] *Energy transition: case for a national energy agency*, Simon Virley for KPMG blog, Feb 2021
[4] *The future of the North Sea*, Nicolle, McAleenan & Birkett for Policy Exchange, 2020
[5] *Network options assessment methodology*, National Grid ESO, July 2021
[6] *Electricity networks strategy group*, Gov.uk, accessed Oct 2021

Question 5: What time period should be covered by a strategic plan and how frequently do you think it should be updated?

5.1. It takes 10-13 years to develop, consent and deliver an offshore wind farm (as described in Annex 1 of the consultation document), and up to ten years to deliver major onshore grid infrastructure. Therefore, any strategic plan needs to look at least 15 years ahead, and ideally longer than this (these timelines, for example, do not include the Crown Estate leasing process). A strategic plan should have a longer term focus and drive longer term broad brush direction of network developments, including anticipatory investment that will help minimise short term changes which create investment uncertainty and risk.

5.2. We agree that having a clear plan out to 2050 (the date of the UK's net zero target) is suitable. However, the strategic plan can be structured such that it acknowledges how longer-term elements are subject to change. Iterations of the plan could look 15 years ahead; in the early years the review cycle could be 2-3 years, with minor adjustments carried out on an annual basis, in order to take into account the volume of change and potential solutions currently being considered. This could move to a five year review cycle once there is greater certainty and consistency, in order to align with the CCC carbon budget periods. Each iteration would be accompanied by a longer-term outlook, based on what the specific 15 year ahead plan would generate.

5.3. *Future uncertainty*: In regard to a strategic plan, it is worth noting that 2050 is still nearly 30 years away with projects contributing to this target potentially commencing development in the early 2040s. It is important to consider that much can change over such a timescale. For comparison, developing a plan for 2050 today is akin to developing a plan in 1990 for 2020. In 1990, the UK was still ten years away from commissioning its first offshore wind farm (in 2000) with two 2MW wind turbines (then the largest in the world). By this time, the Round 1 projects were in development with delivery starting in 2003 – all of these were 90MW or less, using wind turbines no larger than 3MW and mostly connecting at 33kV.

5.4. Projects delivered for 2020 and currently in development are far beyond that which could easily be envisioned in 1990. Whilst we acknowledge that offshore wind has matured significantly since this example period, we can still expect offshore wind turbines and the nature of offshore wind farms to change significantly over the coming decades to 2050 and potentially in a way that is not foreseeable at present. Also, the network charging principles developed in the 1990s are currently still in use in 2021, and this could present significant risk of tariff uncertainty and volatility to some users across the transition to net zero[7].

5.5. In addition to the above, the nature of the onshore system in terms of demand, generation, storage and interconnection is also likely to see significant change. NGESO's document, Future Energy Scenarios[8], looks at various generation, demand, storage and interconnection scenarios out to 2050 and shows just how much change we may see over this period. Transmission technology is also likely to change significantly over the coming decade, particularly in relation to offshore.

5.6. Other big uncertainties include the role of hydrogen in a future energy system, as well as the electrification of heat and mobility - all of which will have significant impacts on the requirements for the future transmission system. Uncertainty should also include

[7] *Offshore wind transmission charges: are transmission charges a barrier to GB achieving 40GW of offshore wind by 2030*, SSEN Transmission, September 2021
[8] *Future Energy Scenarios 2021*, National Grid ESO, July 2021

market design uncertainty; plans for developments such as a European offshore energy pricing zone are advancing, and this may impact on the types of projects being actioned in the 2030s and 2040s, and how a more integrated energy system may work. Finally, there is a balance to be struck between certainty and innovation; for example, we are seeing the fast-paced emergence of floating offshore wind, which might have seemed unlikely five years ago. In our view, a detailed plan every five years with a yearly update looking at very limited or defined circumstances could provide a balance between these opposing elements and balance technological change and policy evolution against the need to provide certainty. It is not necessary to update the full spatial plan every year.

Holistic network design

Question 6: We think that there is a need for a Holistic Network Design that plans offshore transmission for the long-term as an integrated part of a transmission network, do you agree? Please explain your answer

6.1. We agree that there is a need for a Holistic Network Design that plans offshore transmission for the long-term as an integrated part of the transmission network. An over-arching HND will facilitate a move away from individual offshore transmission connections of offshore projects to a model where transmission infrastructure is more shared (where optimal) and where the use of cable corridors and substation locations can be coordinated to reduce environmental and societal impacts. The HND should also consider outage impacts, available technology, and interactions with the distribution network and other energy vectors, where applicable. The offshore wind sector and other stakeholders have been calling for a more coordinated and integrated approach for some time. A level of integration and coordination will still be achievable without an HND but is likely to be sub-optimal and more difficult to implement. We note that to date there has been almost no coordination on the GB electricity network (bar cable routes for the same developer's projects) and no integration, despite some efforts by NGESO to promote it.

6.2. We are pleased to note that in Ofgem's recent publication of its consultation on the initial findings of its *Electricity Transmission Network Planning Review*[9], it is recognised that developing the Enduring Regime provides an opportunity to potentially remove the current regime's distinction between onshore and offshore and move towards a single integrated approach. Furthermore, we agree that there is a clear need to undertake further work to manage key interactions in order to take an integrated approach to network design and delivery across onshore and offshore.

6.3. The HND currently being developed as part of the PW2030 work can be extended for the Enduring Regime and coupled with a strategic plan. It should use similar principles but should be more forward-looking in its pursuit of efficient delivery of grid connections. The PW2030 HND is being developed from an offshore generation map based on Round 4, ScotWind and Celtic Sea leasing. An Enduring Regime HND should incorporate the PW2030 HND and extend it using the following basic principles:

- **Deliverable**. The design needs to be deliverable under the delivery model(s) chosen in the timescales required. Delivery of net zero at least cost to consumers must be

[9] *Consultation on the initial findings of our Electricity transmission network planning review*, Ofgem, 5 November 2021

front and centre.

- **Flexible**. The design needs to retain such flexibility that changes brought about by offshore wind delivery or other factors can be accommodated appropriately.
- **Modular/Scalable**. The design needs to provide for separability of assets at a level suitable for design, consenting, construction and operation to facilitate its delivery and operation within a competitive arena. Minimises the volume of required anticipatory investments.
- **Options approach**. Further to the above point on flexibility, the HND should pass on to the delivery parties a design envelope (options) to work within. This will allow the detailed design and assessment of a range of infrastructure to meet immediate and future needs, allow some degree of flex in terms of technology, and provide latter optionality at point of construction.
- **Phased**. The design needs to phase asset delivery to meet offshore wind project delivery at a tender round, regional and project level. This will allow for asset delivery at the most efficient time ('least worst regrets' for net zero basis).
- **Stable**. During the development of offshore wind projects the regulations should be stable and predictable. This includes certainty around grid connection dates from the ESO/FSO. Changing a process during ongoing development leads to tremendous challenges for both sides; the risk of delays increases, and development costs rise as a lot more optionality needs to be managed.
- **Timely**. The plan should not delay the buildout of individual offshore windfarms.

Other objectives of an HND are as outlined by Ofgem in its consultation on PW2030, namely that it should be economic and efficient, safe, reliable and operable, reduce impacts on the environment and on local communities. As also outlined in our response to Ofgem's consultation, the HND needs to ensure efficient delivery of offshore wind projects, ensuring that individual project delivery is not delayed. This is a major issue for offshore wind developers and investors.

6.4. *HND and TNUoS:* Given that the HND is solely focused on achieving an optimum engineering solution through a centralised approach to increasing coordination and does not provide any discretion to generators about the choice of location, it is evident that locational TNUoS in the context of offshore wind development is not compatible with this approach. This is now part of Ofgem's call for evidence but should be noted here. RUK's views on TNUoS are detailed in our response to Ofgem's recent call for evidence[10].

6.5. A level of anticipatory investment will be necessary, driven by the strategic plan, and this should be set at an appropriate risk level to the consumer. Anticipatory investment for offshore (and possibly onshore) is need in order to unlock investment and remove risk and uncertainty for renewable generation developers. This is currently being addressed through Ofgem's earlier consultation on Early Opportunity projects and PW2030 and solutions should be designed to persist through to the Enduring Regime.

6.6. *Cost efficient provision of ancillary services:* Offshore wind farms and their transmissions assets could be key providers of ancillary services in a net zero system. The current OFTO regime needs to facilitate provision of these ancillary services in a cost-effective manner, for example by allowing OFTO to recoup revenue through use of HVDC converter capabilities. Lowest cost ancillary services may come from offshore windfarms, HVDC converters, onshore hydrogen electrolysers, or a combination thereof. At present, it is unclear how offshore windfarm developers recoup investment in transmission assets which are necessary for connection of onshore flexibility

[10] *Ofgem call for evidence on TNUoS charges: RUK response*, RenewableUK, 12 November 2021

projects. In the short term, there may need to be an amendment to the OFTO boundary definition, removing any regulatory barriers that prevent OFTOs from providing ancillary services from HVDC converters, taking into account impacts and compensation on the offshore windfarms that are involved. Finally, provision of ancillary services may be missing from the technical specification for OFTO 'pipe' assets.

Question 7: If you agree, do you think a Holistic Network Design should also include onshore transmission?

7.1. The HND must include onshore transmission. If onshore transmission is not included, the HND cannot be optimised against the whole system, and may not be deliverable or cost efficient. For the Enduring regime this could be combined with maritime spatial planning to plan in advance where wind farms will be built, grid reinforcements will be necessary, line routing will be. This can provide a proper cost estimate prior any auction and reduce financial risks.

7.2. *Existing FES, NOA and ETYS processes for onshore (and offshore) transmission planning*: the HND should interact with existing onshore transmission system planning processes which include the Network Options Assessment (NOA), Future Energy Systems (FES) work, and the Electricity Ten Year Statement (ETYS). As its name suggests, the ETYS looks at the transmission system over a 10-year period. The NOA uses the FES data and looks (slightly) beyond the next ten years whilst the FES looks furthest ahead, currently up to 2050. There is therefore significant opportunity to align these documents and processes with the HND, noting that the furthest looking also present the most uncertainty and the HND should be flexible enough to accommodate this. This should also be considered in the context of the proposed electricity network strategy, as announced in the net zero strategy.

7.3. One of the issues with the current FES/NOA processes is that the FES data can change significantly year on year. This means that the recommendations of the NOA (which uses the FES data to determine which transmission reinforcements are needed) change regularly, it not being uncommon that reinforcements given a green light to proceed are then stopped sometime later. This is inefficient and drives uncertainty for developers, planners and the public. The FES and NOA should use offshore wind leasing data so as to incorporate leasing up to the 2050 period (and beyond). If this is to come from a strategic plan, then this will give much more certainty with respect to offshore wind development. Given offshore wind will be a major generation source going forward, this will also bring more certainty to the onshore and offshore reinforcements identified as necessary through the NOA, potentially to the extent that many key onshore (and offshore) transmission reinforcements will be clearly identifiable from far out (e.g. well beyond 10 years) hence can be sanctioned to proceed with at an early stage, and can be tracked and evolved up until the point of optimal delivery.

7.4. Additionally, if the strategic plan is in place, the NOA could incorporate it as its baseline, since this could be considered as relatively certain. Less certain elements (e.g. from the FES) to 2050 could then be layered onto this to ensure there is certainty with the delivery of onshore and offshore transmission to meet an offshore wind strategic plan along with flexibility for less certain other future system impacts. Given the increased certainty this approach would bring, it will also be possible to carve out key baseline reinforcements onshore and offshore that are required for offshore wind and even remove them from further NOA assessment.

7.5. *Transmission charging*: Within the consultation, BEIS notes that the move to a strategic plan and associated HND could lead to uncertainty over the transmission charges offshore wind projects will be subject to and this will be an issue for project economics and CfD bidding. Given an HND will be established at an early stage, transmission charges can be calculated using HND technical data and costs using whichever charging methodology is eventually finalised for offshore transmission. This information can then be factored into project economics and CfD bids. There will be some level of variability in the charges, but this should not be more than a developer should face within the current regime. Any volatility in the transmission charges will however be an issue and this is something that will need to be assessed carefully as part of a new charging regime (the current codes specify that the current transmission charging regime should not be volatile as a fundamental principle).

7.6. It is crucial that the HND takes into account that the planning and consenting processes (in England and Wales) are based on statutory timelines, with a clearly defined process, and that in Scotland there is an entirely different consenting regime. An extension of the UK MITS closer to the offshore landing point could help to address many of the onshore coordination issues more strategically.

Question 8: Who do you think is best placed to undertake a Holistic Network Design? Please explain your answer.

8.1. The current HND, as part of the PW2030 work, is being undertaken by NGESO. From a high-level transmission system perspective, NGESO or a similar party would seem most appropriate. In this respect, we note the recent consultation on a potential Future System Operator[11]. This will require stakeholder consultation, in particular in the offshore system planning area, where NGESO have limited knowledge to date.

8.2. It is also possible that a separate 'design authority' could be created to oversee the HND, separate to NGESO or a future FSO. Whichever party is tasked with HND, they will need to be suitably independent, resourced, and skilled. There will also need to be robust processes developed to ensure relevant stakeholders are properly engaged and feed into the process. This will ensure the HND takes into account the wide range of issues it will need to as appropriately as it can. The HND will only be able to provide a broad-brush outline, as the planning process within the UK is designed to demonstrate that appropriate consultation has taken place and that detailed design and consideration of options has evolved whilst taking on board consultation feedback. We are concerned about the risk of the HND and planning processes conflicting with each other. This will need to be considered when thinking about the delivery models and interaction with whoever carries out the HND role.

8.3. Whichever party undertakes the HND must have or be able to use all the necessary expertise. For example, consenting aspects such as environmental and coastal community impacts will be important, as will seabed conditions and infrastructure and anthropogenic issues. This means that the design eventually taken forward through consenting to construction will need to consider many multi-disciplinary aspects.

8.4. As the assets will be taken forward from HND by a delivery party which is not likely to be the HND designer then most of this will likely be undertaken in much more detail by the delivery party. However, the HND will need to have given some level of

[11] *Proposals for a Future System Operator role*, Dept. for BEIS & Ofgem, July 2021

consideration to these issues to ensure it is likely to be deliverable and to provide an envelope within which the delivery party can work. It is important that the HND is deliverable and the party taking on the future onshore and offshore grid works can rely on the output to progress the next stage of the delivery process.

Delivery models

Question 9: Which delivery model would provide the appropriate balance of incentives and cost savings, given the Review Assessment Criteria (Annex 4)? Please explain your answer

This question could perhaps be rephrased to ask **which delivery model is best to deliver the objectives of the OTNR** and meet the Review Assessment Criteria of Annex 4 of the BEIS consultation. This will need to consider a number of issues, although we agree that the delivery model will need to strike an appropriate balance of incentive and cost savings.

9.1. *Relevant Review Assessment Criteria*: The Review Assessment Criteria of Annex 4 are reproduced at very high level below. The HND will address many of the Review Assessment Criteria with the delivery models more relevant to a subset of criteria. We see the delivery models as primarily needing to consider impacts on deployment, competition and risk allocation. End consumer benefit is partly captured by an appropriate HND and then partly in cost efficient delivery. On this basis, we do not comment further on the deliverability of policy and regulatory changes, decarbonisation, environmental impact, or local community impact with respect to the delivery model options.

#	Name	Description
1a	**Deliverability**	The policy, regulatory and other changes need to be deliverable in the timelines required for the projects that will fall in the Enduring Regime
1b	**Decarbonisation**	The option(s) chosen supports the decarbonization agenda, 2050 targets and Net Zero.
2a	**Deployment impact**	The option chosen speeds up deployment of offshore wind compared to an uncoordinated solution (this cutting across multi-disciplines including environmental and consenting factors).
2b	**Renewable generation competition impact**	Maintains an effective competition regime and level playing field for the various renewable energy participants.
2c	**Transmission competition impacts**	Increases or maintains and does not distort competition in transmission.
2d	**Risk allocation**	Places risk on those best placed to manage it and covers generation, transmission, and other transmission users.
3a	**Environmental impact**	Significant impacts on the environment are avoided, minimised, or mitigated by coordinated transmission.
3b	**Local communities' impact**	Impact and mitigation on local (including coastal) communities impacted by construction of 'onshore' assets and related activity.
4a	**End consumer net benefit**	Has a positive impact on consumer savings (this is primarily a monetary issue).

9.2. *Timeline issues*: we have already outlined the need for the Enduring Regime to build on the shorter-term work of the Early Opportunities projects and the PW2030 projects, unless a different solution is clearly better. We are pleased that BEIS has acknowledged this approach but also opened the door for a more radical rethink, given the longer timelines available. Although 2030 is still nine years away, the implementation of the Enduring Regime is much more urgent than that. In reality, to implement the Enduring Regime on post-2030 projects means deciding upon and implementing the regime within the next few years. Projects for post-2030 will start their development phases within the next few years and certainly ahead of 2025. Any delays with the Enduring Regime implementation will likely delay the next few rounds of offshore wind projects and could at worst affect developer and investor confidence meaning some projects may not proceed. The next few years will likely account for many projects in the 2030 to 2040 timeline and may well account for a very significant amount of what is needed by 2050. Therefore, we do not have the luxury of taking time with the Enduring Regime but must develop and implement it quickly and effectively. Some disruption is inevitable, but the longer it takes to transition, on the presumption that build-out will accelerate, later changes will be much more painful if not well managed.

9.3. *Progressive cut over from the Pathways to 2030 (PW2030) delivery model(s):* In addition to the above, projects in the PW2030 may well be subsumed into the Enduring Regime where appropriate and once the arrangements are in place. However, perhaps more importantly, projects which nominally fall into the Enduring Regime may be best delivered under the PW2030 delivery model, particularly where there is an element of progression and cut over, e.g. where an OFTO or ITO is being encouraged to undertake construction but a sudden jump to an early OFTO or ITO in the Enduring Regime might be inappropriate. This progressive transition approach could support de-risking the delivery of post-2030 projects that will be first in line within an Enduring Regime, and could form part of sensitivity study cases to be assessed within PW2030. In any case, the transition from PW2030 to Enduring Regime should be well prepared in advance.

9.4. *Delivery models and the role of developer-led*: BEIS has outlined the delivery models it sees as appropriate for consideration, and this is in keeping with Ofgem's PW2030 consultation from July 2021. RUK provided extensive commentary in the Ofgem consultation, and will also do so to an extent here. We note however that the PW2030 is primarily focused on the urgency with delivery and as a result, the best options for PW2030 are not necessarily the best options for the Enduring Regime. It is important to understand how the balance of risk will change as the market continues to expand. From a short-term single project delivery perspective, it is entirely logical for developers to favour a high degree of control. As the volumes of offshore wind increase and have a greater impact on onshore networks and wider network planning, it is not clear if developers have all the information to make informed decisions that would lead to the best outcomes for consumers and most efficient transmission solutions. With this in mind, we highlighted the benefits of a TO delivery model with later cut over to an OFTO. We also highlighted that a **developer-led model with later cut over to an OFTO** was a preferred model by developers and, in our view, the best model for 2030 delivery. It is the developers who have nearly all the design, consenting and construction experience for offshore transmission to date and are almost certainly best placed to take it forward in the near-term.

9.5. For the Enduring Regime, we believe that a developer-led model should continue to have a role, but that (earlier) OFTO/ITO models can also be developed and implemented. A developer-led approach should continue where radial solutions are deemed the most appropriate approach, but we query how well-placed developers are to carry out integrated offshore transmission infrastructure on behalf of potentially multiple developers. A non-developer-led model is likely to be needed straight away and therefore the ITOs would be required when not yet experienced. (An exception to note: an ITO could be a TSO from another market making their entry into GB, and in this case they would have good experience). We therefore see merit in a TO-led model being explored further with a phased approach in place to allow the ITO a larger role in the process over time. Given the timeline issues highlighted above in relation to implementation of the Enduring Regime, it is hard to see how a delivery model that is not initially developer-led can be excluded without significant disruption and delay to project delivery. Given the scale and speed of development required, it is vitally important that a combination of delivery models is available as a flexible approach will be needed, at least initially.

9.6. *Additional developer-led models:* In the PW2030 consultation, we highlighted to Ofgem that further developer-led models exist. Table 1 from the consultation document is reproduced below. Option 6 is the equivalent of the current developer-led model but with the introduction of the HND. However, the ITO (OFTO) could be introduced at earlier stages and the developer-led (post HND) model be analogous to options 3 and 4, where the developer hands over to an ITO (OFTO) for construction, or, consenting and construction. An option to introduce an OFTO/ITO for construction could be beneficial in reducing costs. This means that BEIS should be considering at least two further models which involve the developer, and which allow the introduction of an ITO (OFTO) at earlier stages. Also worthy of note is a developer joint venture model which could be used for more extensive and shared offshore transmission.

Table 1: Possible Offshore Transmission Delivery Models

	Holistic Network Design	Detailed network design	Pre-construction (e.g. consenting)	Construction	Operation
1. TO build and operate	ESO	TO	TO	TO	TO
2. TO build, ITO[20] operate	ESO	TO	TO	TO	ITO
3. TO design, ITO build and operate (Late-competition)	ESO	TO	TO	ITO	ITO
4. Early ITO competition	ESO	ESO or TO	ITO	ITO	ITO
5. Very early ITO competition	ESO	ITO	ITO	ITO	ITO
6. Developer design and build, ITO operate	ESO	Developer	Developer	Developer	ITO
7. Current approach – OFTO regime	N/A	Developer	Developer	Developer	OFTO

9.7. *Third party models*: Third party models are also worth considering. This could be a party willing to progress the offshore transmission works but not wishing to either construct and own, or own, at which point an ITO is introduced. There are many organisations which are geared to consenting infrastructure and then selling it on, or that are geared to delivering infrastructure but not owning it. Many of these organisations are used to dealing with tight timelines and appropriate contracting structures, including incentives and penalties such as liquidated damages for late delivery. The use of third-party models may also depend on whether the Enduring Regime considers that opportunities exist to build scale in the ITO market and capture synergies between projects and wider system planning integration.

9.8. There is a real challenge to ensure that the correct incentives are in place to drive efficient design and future ownership arrangements. A consenting organisation that is tasked with delivering consent for a given price before handing over to someone else to build and operate will be less worried about the challenges that consent requirements have for the construction or operational teams. If value for money and end-to-end efficiency are the key drivers, then an end-to-end view needs to be taken. A balance must be struck between cost and timescales across design, consent, build and operate stages of transmission asset lifecycle. Careful consideration of incentives for different parties involved at different stages of the development and delivery of the assets will be needed if optimal and efficient decisions are to be made.

9.9. *Detailed Network Design and ITO tendering*: In our response to Ofgem's consultation on PW2030, we highlighted that a delivery model which effectively stops whilst detailed (electrical) design is carried out would introduce a delay in the order of 6 months, and a model that needs to effectively stop while ITO tendering is carried out would introduce a delay in the order of 12 months. For the PW2030 project, these delays are very significant and should be avoided. We further noted that network design is normally a progressive process throughout delivery and normally only undertaken in detail (and finalised) at point of construction – thereby better managing risks and costs. These delivery model steps (and their consequent delays) should also be carefully considered in the Enduring Regime; review assessment criteria 2a is about speeding up deployment of offshore wind.

9.10. *Detailed summary comments on the delivery models*: We have already made some important comments above and below sum up a view of the options in a table. BEIS may wish to access our response to Ofgem's earlier consultation for more explanatory detail.

<table>
<tr><th>Delivery Model</th><th>Key Considerations</th></tr>
<tr><td>1. TO Build and Operate</td><td>Option 1 does not facilitate competition and would involve legislative challenges since an offshore licence would not be awarded competitively.
TOs presently have little to no resource or experience with offshore transmission. Ownership introduces an incentive for the TOs although there is lack of incentive for timely delivery (we note that incentives could be developed).
Delivery by a single party (extending its asset base from onshore) reduces interface risks and could be relatively quick, assuming the incentives are there for a speedy delivery.</td></tr>
<tr><td>2. TO Build > ITO Operate</td><td rowspan="2">Introduces mid to late competition. Presently little to no resource or experience with offshore transmission in TOs.
ITOs will need to develop expertise and resource for earlier involvement but are already experienced in operation.
There is little incentive for onshore TOs to take forward infrastructure they will not own and a lack of incentive for timely delivery by the TOs or ITOs (e.g. no liquidated damages).
Construction costs could be reduced in option 3 since ITO can be expected to have lower financing costs. Financing costs would be expected to increase from current OFTO levels if ITO are taking development, or interface risks with wind farm and TO.</td></tr>
<tr><td>3. TO Design > ITO Build and Operate</td></tr>
<tr><td>4. Early ITO Competition</td><td>Both options 4 & 5 can promote competition and innovation. ITOs will need to develop expertise and resource for earlier involvement but are already experienced in operation.</td></tr>
</table>

5. Very Early ITO Competition	• Early or very early ITO tendering is likely to introduce a 12 month+ delay as the development processes are paused. • The correct processes and incentives will need to be developed for the ITO although this may be common with and use work on onshore competition. This will need to include incentivisation for timely delivery. • Costs could be reduced for financing and ITO costs may be lower than TO costs in general terms, however, such early appointment will make it challenging to control costs down which could end up being more expensive for the consumer compared to ITO build and operate or ITO operate options. The uncertainty associated with planning, design and consenting requirements will make it difficult to have certainty on costs as part of any tendering process. Parties competing for early ITO award will need to be assessed on factors other than cost as the level of uncertainty will make comparison between tenderers impossible. • BEIS should ascertain the appetite amongst ITO for early or very early introduction. Each ITO should have clear interface agreements for where they interact with each other or the onshore TOs.
6. Developer design and build, ITO operate **8. Developer design and consent, ITO build and operate** **9. Developer design, ITO consent, build and operate**	• Introduces late competition in option 6 but earlier competition in 8 and 9 which will require ITO to increase expertise and resource. • Developers are used to managing the risks and incentivised to deliver by getting their projects connected on time, however, there are questions over the incentives for works to get other developer projects connected and how risks are shared. • Developers are already experienced and well-resourced for delivery. • This model raises commercial risks when considering multiple developers in one zone. • Questions to be addressed about sharing of information and how developer competitive pressures will be managed. Developers are incentivised to drive down offshore transmission costs as these flow into developer transmission charges. • Earlier ITO involvement at construction could reduce costs due to financing but need to consider incentives for timely delivery. • Option 6 is well established, efficient and involves competitions with no delays due to detailed design or ITO tendering.
7. Current approach (no HND, developer-led, ITO operate	• We assume this model will no longer exist and is effectively supplanted by model 6.

Note: the table assumes that OFTO equals ITO - this is not always the case. ITO could refer to a TSO from another market making their entry into GB (assuming this is permitted). Therefore they would have good experience.

Timing of detailed design and delivery of transmission

Question 10: At what stage should the detailed design and construction of transmission be conducted? Please be clear about which approach your comments relate to.

10.1. *Detailed design*: We have already commented briefly on detailed design in our response to **Q9** of this consultation, but will expand further here. Overall, we see design as a progressive process, only necessarily finalised when construction is to be undertaken. Delivery of assets should be timed for when they are required; for example, connections for offshore wind projects must be delivered prior to the project's connection date, and wider system works can be timed for optimal delivery on other criteria (such as minimising costs or coordinating work in a sensitive coastal location). If that involves an asset being considered anticipatory investment then as long as there is a clear charging mechanism to share that with consumers, it should be delivered when the first project needs, not the last project that needs it and the others have to wait. The NOA currently seeks to help time delivery of wider system works. This has many advantages, including but not limited to the following:

- Retains different design options until a final decision must be made at point of construction
- Retains flexibility, including within the consents
- Allows for innovation or late design changes
- Allows for design optimisation and cost efficiency throughout the development process

10.2. To date, developers of offshore wind farms have undertaken the design of offshore transmission in a progressive fashion. The normal starting point is a connection agreement with NGESO which specifies connection location, provides design parameters from the codes, and lays out a starting design. This position would be broadly analogous to the point at which the HND is fed into a developer's connection agreement, providing the above along with additional and more prescriptive details such as additional functionality for integrated design purposes and specifying cable corridors to be used. The developer then establishes a set of design options which are continually reviewed, updated, and reassessed. In the current system these are fed into the CION process to ensure the new offshore transmission is optimised with the wider transmission system. The options are used to define consenting envelopes and other parameters. Once consented, the design will normally be refined, and a final option chosen for construction. This will be subject to a FID before construction is undertaken. In some cases, the developer provides the final design and in others the appointed construction contractor will provide the final design as part of its construction contract.

10.3. Similar processes are also undertaken by onshore wind farms and other renewable energy projects, albeit not involving the transmission element. We understand that onshore TOs tend to fix their designs at earlier stages, generally because they work with a more limited set of design options and more standard technologies and wish to progress consents for a specific design. However, we do not believe this early lock-in of design detail as appropriate, as it does not retain the advantages outlined above. Given that the HND will need to retain flexibility and that the most suitable solutions for offshore transmission will continue to evolve, we believe a similar approach to offshore transmission design to that of an offshore wind developer is appropriate in delivering the best overall solutions with least risk and cost. We have outlined some of the key tenets for an HND in our response to **Q6** of this consultation.

10.4. *Construction and final delivery*: In the current developer-led (generator build) model, construction is undertaken to deliver when the wind farm requires the infrastructure (albeit this is often delayed due to onshore grid constraints and the timing of reinforcements). In this model, the developer controls the delivery processes of the offshore transmission assets and will only commit to construction once a FID (for the offshore wind farm and offshore transmission assets together) has been made. This means that commitment to major spend on construction is undertaken jointly for the offshore wind farm and its offshore transmission connection thereby minimising (in practical terms eliminating) the risk of stranded assets. Spend ahead of construction is normally relatively small in comparison. All in all, the delivery programme should not delay the buildout of offshore wind.

10.5. If there is a move away from a developer-led model, can transmission works be conducted at the same time as the construction of the offshore wind farm, and not risk delaying the project? If not, there will need to be some sort of trigger to start construction ahead of windfarm FID. Alternatively, if the HND identifies transmission works well in advance of project leasing and project delivery commencing, then the works can be delivered earlier than the project. Ideally, the transmission works required for a project to connect will be designed and consented ahead of the offshore wind farm, and can sit waiting for the offshore windfarm to consent and achieve FID. All the work up to this point is relatively low cost and low risk.

10.6. NGESO/TOs currently manages connection agreements and delivery of specific transmission works in a similar way. In cases where the transmission works can be constructed faster than the connecting project, it normally seeks evidence of a project's FID before making its own FID and committing significant spend to construction and delivery of transmission infrastructure to meet its connecting project timelines.

10.7. A connection agreement between NGESO and a connectee will contain the transmission works required for the connectee and a programme of milestones for both parties. Regular meetings allow adjustments of the programme for both parties as necessary, reduce risks and control spend appropriately against uncertainty. In this method, consents can be largely decoupled from each other (connectee and transmission works) with any final design and construction (meaning major spend) only occurring once consents and FIDs have been made. For the most part, we do not see a need to approach detailed design and construction of offshore transmission any differently. This is a later construction model which retains flexibility, manages risk, and keeps spend controlled accordingly, but delivers as the case for delivery becomes stronger. There will be instances where construction will need to start in advance of the connecting project, and this will involve some risk. Currently a windfarm developer is not compensated for grid delay, in a third party model this arrangement would ensure that windfarms are kept whole for auctions outside of their control, and it would act as an incentive for the grid developer to connect on time.

10.8. *Connect and Manage:* For onshore transmission works, the **Connect and Manage** regime is used. Connect and Manage allows generators to connect to and use the onshore transmission system provided essential and local works for connection are complete, but accepts that the wider system may not fully accommodate the generator. In simple terms, the costs of generator constraints are accepted in the interests of getting renewable energy into the system as fast as possible, with transmission infrastructure to relieve those constraints following on later. In the modern world of transmission, it has become accepted that it is often more economic to constrain generation than it is to build new infrastructure. Managing and optimizing this balance is an important (and growing) role for NGESO. The Connect and Manage regime does not currently apply to offshore transmission works. Given we are moving towards a more substantial and integrated offshore grid, where offshore transmission may perform functions akin to the wider system irrespective of connected offshore wind, and there may be discrepancies in delivery of such transmission infrastructure compared to offshore wind, the Connect and Manage regime should be extended offshore. NGESO and Ofgem should be given this as a mandate.

10.9. *Wider offshore transmission and early/late delivery*: Additionally, there are offshore transmission assets that will perform a wider system role and can be decoupled from delivery of assets that are absolutely required to connect offshore wind. For example, two offshore wind farms could be connected to shore by individual links but for system purposes an offshore link between them could be required. The offshore link could be delivered after the radial links and offshore wind farms, provided the offshore link functional requirements and associated anticipatory assets have been appropriately designed within the development stages of the individual links. It is therefore important that further to the HND, offshore transmission is subjected, where appropriate, to NOA type processes which determine both value and optimal delivery dates. However, this should not prejudice connection of offshore wind, and it will be important to classify the different offshore transmission works appropriately and deliver them accordingly. For onshore, NGESO currently classifies works that must be completed before a generator connects as 'Enabling' and those the Generator need not wait for as 'Wider'. A similar approach should be taken offshore. Those delivering Enabling works will need to line their programmes up against the offshore wind project(s) to ensure timely delivery, whereas those delivering Wider works may have delivery timescales determined by other factors such as the NOA outcomes, cost efficiencies in conducting offshore works together, consenting constraints, or commitments to coastal communities. We note that interface risk is a concern for HVDC delivery and alignment between the onshore and offshore systems is critical. In addition, alignment of incentives is key to ensure holistic optimisation of the design.

High-level approaches

Question 11: Do you have any views on the relative merits of these high-level approaches?

11.1. When assessing the post-2030 offshore wind delivery models, we have considered where the industry is today and how capacity buildout is likely to change as we rapidly decarbonise our economy and look to deliver on the UK's net zero targets. The Climate Change Committee (CCC) indicates that the UK could require up to 125GW of offshore wind by 2050[12], a very large increase from the 11GW installed today or the 40GW target set for 2030. We believe that meeting these targets may require BEIS to consider a more strategic approach to offshore wind delivery. A suitable high-level approach must be focused on delivering the volumes of offshore wind required to decarbonise, as well as speeding up the delivery process (which is currently 10-13 years per project). It must aim to manage the risks that offshore wind project face; balancing offshore wind delivery and the economic value that offshore wind delivers against environmental constraints, sea co-use and local stakeholder concerns. We believe that improved coordination of offshore wind sites (where it is economic and in the consumer interest to do so) could be a key benefit of a more centrally administered delivery regime.

11.2. In this section, we consider each of the high-level approaches covered in the consultation document, setting out the notable benefits and potential drawbacks for each. At this stage, we have chosen not to endorse any particular high-level approach – more details are needed on the detailed delivery models, strategic plan and HND before a final decision can be made. Investment in an offshore wind farm is triggered by several key factors: getting consent, obtaining a viable grid connection, having programme certainty, sound business case. The challenges of complex multiuse connection schemes will impact all of these factors. Whichever high-level approach is adopted, efficient transition arrangements from PW2030 to the Enduring Regime need to be considered, to provide continuing certainty and avoid a pause in development. We recommend that BEIS considers a further deep dive and detailed consultation on the models; going forward, further details could be shared with stakeholders such as

[12] *Balanced Net Zero Pathway, 6th carbon budget*, Climate Change Committee, 9 December 2020

risk & mitigation mapping and RASCI matrices[13].

11.3. *Approach #1 (incremental change):* Approach #1 retains a version of the developer-led model in use today. We have seen the clear advantages that the early developer-led approaches have had in the UK in terms of managing project delivery risk, fostering competition and innovation and getting projects built. This approach has successfully delivered over 10GW of offshore wind onto the GB network, and will likely deliver 40GW of offshore wind by 2030, based on the existing pipeline of projects[14]. However, projects are considered on an individual basis, which may create challenges as we look to ramp up volume and deliver faster. Other points to note include:

- Developers and investors are familiar with the system. Developers are in control of surveying, design, and construction, and can optimise sites as desired.
- A single organisation is responsible for all the key consenting works as the OFTO and wind farm consents are intrinsically linked. It is in the developers interest to tie both of these together in a timely manner and they are in a better position to determine which areas of the proposed development can be compromised to meet the needs of external stakeholders. This also lowers the risk of stranded assets.
- The CfD has substantially lowered the LCOE from offshore wind farms, from £150/MWh in the 1st CfD round, to £44/MWh in the 3rd CfD round[15].
- There is a higher risk of abandoned assets as project impacts are not considered holistically – cumulation risks are difficult to manage and double competition adds to project delay and uncertainty.
- If approach #1 is followed, it is important to incorporate HND; the PW2030 workstream includes an HND, so not including it here would be a step backwards.

11.4. However, while the existing developer-led model has been successful thus far, it is vital to further speed up deployment of offshore wind, in order to reach up to 125GW by 2050. One of the purposes of the OTNR review is to establish a new approach, and it is clear that sticking with the point-to-point method of grid connections is not sustainable. A different approach could speed up delivery of new wind farms, optimise grid connection infrastructure and reduce the impacts on coastal communities (as well as other communities near substantial onshore grid works). The consultation document suggests introducing new incentives to encourage greater coordination between developers. The national policy statement (NPS) could provide a framework to ensure that greater coordination occurs, but currently there is little information on how this would be facilitated, and it could lead to further challenges in the planning process.

11.5. *Linked CfD bids:* RUK members are concerned that including linked bids in the CfD would fundamentally change how auctions are run, increasing complexity and consequently costs. For instance, if one party in a linked bid clears the CfD auction but the other does not, how would the project proceed? There would be a high risk of delay, and a lack of control here will impact on developers' commercial strategies. The decision to integrate transmission assets needs to be taken several years before the CfD bid. Linking bids between different developers will require sharing of commercial and technical information that many developers will not be comfortable with; a solution to these challenges will need to be found. There could be scope for linked proximate projects from the same developer which could circumvent these issues.

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[13] RASCI = Responsible, Accountable, Supportive, Consulted, Informed

[14] The UK portfolio of offshore wind currently has the potential to deliver more than 63GW of offshore wind if fully constructed – source: RUK Project Intelligence, September 2021 report

[15] *Analysis: record-low price for UK offshore wind cheaper than existing gas plants by 2023*, Carbon Brief, Sept 2019

11.6. *Approaches #2a and #2b:* Moving towards a more coordinated approach has significant potential to streamline the offshore wind process, and reduce project delivery time. This would potentially bring together seabed leasing, revenue stabilisation and coordinated grid planning. Care must be taken when bringing together multiple complex processes - our members worry that a more centralised plan could limit innovation and the competitive edge that private sector developers bring to the market, unless wide parameters are set by Government. A more centralised approach may mean that developers have less certainty to inform their bidding strategies, unless more development work is completed upfront.

11.7. *Seabed leasing*: If these high-level approaches are adopted, greater clarity is required on the future of seabed leasing rounds. In a more centralised model, the Crown Estate/CE Scotland would need to carry out surveying to an industry level standard that can be relied upon by the developer, with sites determined by the strategic plan. In order to reduce uncertainties about the seabed lease, parameters would need to be provided to allow developers to hone planning approval and the level of information that the supply chain could provide at that time to inform bid price formulation. All these factors would mean that if an auction style system remained, there would need to be much greater flexibility for developers or clear contract reopeners. The leasing of consent sites model could reduce these risks.

11.8. *Approach #2a (HND and delivery):* RUK and our members think that approach #2a could work well, provided there is a strategic plan in place. With no plan in place to work to, the HND is essentially just an updated CION, and will not provide the same level of coordination or holistic thinking. Timing is important, and members are worried about the risk of a time lag of 12-18 months between the HND and the contracted grid position with TOs. To avoid this, the connection agreement should be provided alongside the site lease. Wind developments generally take a FID on known and stable regulatory and market arrangements. These arrangements impact the cost and financing of a project. Therefore, any change in market design would need to carefully be considered, especially where any negative impact on the windfarm revenue could have a knock on effect on investor confidence. However, we believe that this is a transitional timing issue that can be limited by clear change roadmaps and timings.

11.9. HND with early transmission delivery is a weak proposition. While early design of transmission is sensible, and could save time and money, early delivery of offshore transmission before seabed leasing risks building infrastructure for a windfarm that is not successfully delivered. A solution to this would be if the strategic plan concept were also introduced alongside early competition - i.e. a tender is undertaken well in advance of a seabed leasing round so that upon award of the seabed lease (and perhaps financial support and/or grid connection), an OFTO is already well into the detailed network design and consenting stages of the development process.

11.10. *Approach #2b (Holistic network design with combined seabed lease and financial support):* This approach would lead to a total overhaul of the whole of the UK offshore wind market, and change how offshore wind is developed in the UK. It would require an integrated agency to manage all aspects of this competitive process who would be in a position to guarantee the grid connection, generator revenue during operation, and consent for both the windfarm and transmission scheme. Wide project parameters could ensure this approach allows for some innovation, but would ideally need to be complemented with the developer-led approach in GB that delivers high-value projects at pace. The greatest risk for approach #2b is the early award of a tariff, in this case circa 9 years before delivery. Due to the immaturity of projects at that stage, developers may not yet be able to hone bids. We also note that this approach could preclude alternative routes to market or new delivery models.

11.11. The benefits of this approach can be seen in Germany, which has been running a version of #2b for over 10 years at this point. While the risks to the developer are much lower, it would require an equivalent agency like BSH (German Federal Maritime and Hydrographic Agency) who would remove the need for the BEIS/Planning Inspectorate consenting process, as well as imposing clear penalties and processes on the TO should they be late to deliver. Notwithstanding the points made in paragraph 11.5, combining seabed leasing with the CfD auction (for single projects) may actually reduce delivery risk, as there would only be one round of competition that developers need to clear, increasing investor certainty. The leasing and consents processes for offshore windfarms currently take too long, so this could help to speed up proceedings.

11.12. A variation on approach #2b which considers the lease award of consented sites removes some of these challenges as the tariff award is later in the maturity process and the consented project is more likely to be built. Early certainty on the progression of projects and tariffs provided by the combined models would remove competitive tensions later in the process. This may foster greater collaboration during the design and construction phases, leading to wider developer cooperation. In addition, the variation would ensure that the status of grid and offshore wind consents are known before lease, reducing the risk of leasing a windfarm and grid consent failing. Overall we believe this would increase investor confidence. However, it would entail significant capability building within the leasing body or within Government departments.

11.13. RenewableUK members have concerns about the process becoming more centralised with limited developer involvement. Over many years, developers have established a deep in-house expertise on consenting which has sought to achieve the most efficient long-term solution for a particular site and technology. It is important that the priority for each site is for it to be optimised to continue delivering the innovation seen in the industry to date. Some of the questions around approach #2b are detailed below:

- Following approach #2b would require a fundamental restructuring of the CfD and Crown Estate leasing rounds (plus ScotWind). What would happen to AR4 leases, or would changes be implemented in AR5?
- What would the impact be on previous generations of projects – who may be re-powering, bidding into CfDs etc.
- To what degree would government share DEVEX and CAPEX risk when using this approach (currently developers take on all the risk)
- A wider Rochdale envelope will be required

11.14. *Transitioning to a new approach:* If either approach #2a or #2b is implemented, care will need to be taken in the transition stage, as we move away from the current developer led model. There may be a situation where different regulatory environments are being run at the same time. In Germany, there were issues where leases were taken away from developers – avoiding a similar scenario is important. Any new approach will need to have transitional requirements for consenting – to deal with the risk that the HND or other strategic plan comes out when projects are at advanced stage and to avoid pressures to delay applications or refuse consent.

11.15. *Additional high-level approaches*: We consider that in the future, a number of offshore projects may be developed that could proceed to FID stage without requiring a partial/full CfD (they may use PPAs etc.) Therefore using the CfD as a basis for transmission design/delivery model may not be applicable to all projects. The Enduring Regime should consider if merchant project approaches potentially fit within options

#1, #2a and #2b, or if an additional delivery model option will be required for such projects, that may wish to progress at pace the development of their transmission development outside of the signal provided by the CfD process[16]. Also, offshore wind projects that would require grid connection for part of installed capacity with the other part supplying offshore demand (e.g. hydrogen production, MPIs) may require an additional delivery model that ensures development can progress within the strategic plan considerations.

Facilitating Multi-purpose interconnection

Question 12: Does the current legal and regulatory framework, and Ofgem's options to regulate within that framework as described in the Ofgem consultation, provide an adequate enduring solution for the regulation of MPIs? If not, please indicate why not and what changes you think may be needed

Our responses to the MPI questions in the consultation document are detailed below. However, we would also like to note that in a fully integrated onshore and offshore transmission system where the distinction between onshore and offshore has been removed, an interconnector would cease to be an interconnector and become part of the GB transmission system at the first point of connection with the system. That first point of connection could be at an offshore location, rather than at the point of landfall as is the case at present. In a future integrated system, the majority of the potential issues currently identified for MPIs would not arise in the first place, as the GB system boundary would be offshore. With this in mind, we recommend that any further consideration of MPIs is carried out in the context of the goal of a fully integrated system.

12.1. MPIs will have an important role to play in delivering net zero at least cost to the consumer, and meeting the Government targets of 40GW of offshore wind and 18GW of interconnection by 2030. An Enduring Regime will need to coordinate changes to legislation, codes and methodologies in order to enable MPIs on the electricity grid. The current legislation for interconnectors (*Electricity Act 1989*) was not developed with MPIs in mind, and instead defines interconnectors as point to point connections with other countries. MPIs also do not fit into the definition for offshore transmission, which only considers a radial link connecting a single generator back to the shore. The current regulations do not provide an easy mechanism for these elements to interact through licensing, connection policy, charging or ownership. Current legal and regulatory frameworks focus only on existing onshore transmission with 'bolt-on' regulatory arrangements for offshore transmission. Therefore, we would welcome a change, wherein the compartmentalisation of the transmission system between offshore and onshore is reduced or removed. As mentioned earlier in this response, development of an integrated offshore and onshore transmission system is needed in order to support the overall delivery of net zero.

12.2. For the Early Opportunities and PW2030 workstreams, we recommended that Ofgem should accommodate both IC-led and OFTO-led models. The different models reflect the fact that there are different configurations for MPIs, depending on where offshore

[16] *How 2021 could be the year that oil and gas majors crack the offshore wind industry*, Everoze, December 2020

generation connects. A version of the current cap and floor framework[17] could be applied to early MPIs, however they may require more bespoke arrangements in order to attract stakeholders and mitigate risk.

12.3. We note that Ofgem's recent consultation did not take account of the long-term goal of a fully integrated system both onshore and offshore, taking into account the underlying purpose of the transmission network and the ways in which it delivers an efficient outcome for both generators and consumers. As such, moving forward both the IC-led and OFTO-led models may not be suitable for an enduring solution. MPIs should be classed as their own asset within the regulation framework; the current framework is too restrictive and limits the benefits of MPIs. MPIs are complex and require significant alignment across geographies and markets, projects, regulatory landscapes, and technologies therefore the option to continue to develop individual host projects is important. There is no standard design for MPIs; some may be more focused on cross-border electricity flows, while others primarily function as transmission for offshore wind farms. The balance between transmission and interconnection may change for an individual MPI asset during its operational lifetime – this flexibility should be reflected in the legislation and regulation for MPIs.

12.4. A review of the licensing regime and legal definition for MPIs would be welcome; at the very least, a clear understanding is required of how OFTO and interconnector licenses can interact and how an MPI operator can deliver both transmission and interconnection. A review should consider the following points:

- An MPI licence that allows for the license holder to exercise more than one function. Further, a review of the ownership requirements, ensuring that an MPI operator can own and optimise the whole offshore cable network, reducing interface risk.
- Potential barriers to MPIs caused by the 70% merchant requirement rule (Regulation on the internal market for electricity (EU) 2019/943[18]
- Allocation of congestion rents to third parties
- Clarification on how CfD eligibility will be affected if an offshore wind farm connects to an MPI.
- Alignment between the development consent order (DCO) process and MPI development, ensuring the DCOs do not prevent MPI progression
- A review of the TNUoS charging framework, ensuring that MPI developments are not disadvantaged by the TNUoS methodology
- An alignment of connection management regimes for MPIs, which covers Connect & Manage for offshore generators and Invest & Connect for interconnectors
- A review of the connection policy that allows an interconnector to connect to an offshore node
- A model for recovery of any anticipatory investment required by a generator or OFTO to deliver an MPI, and early gateway approval to move forward with MPI development

In addition to these points MPIs require alignment on the technology (voltage levels and interoperability), alignment on the development timelines between host windfarms and the interconnector, FID and scheme alignment between the Cap and Floor and CfD (or another scheme like RAB if this is deemed more appropriate for the Enduring Regime).

12.5. Ultimately, either legislative and regulatory flexibility will be required to use the existing

[17] *Guidance on the cap and floor conditions in the electricity interconnector licence for projects seeking project finance funding solutions*, Ofgem, 18 June 2021
[18] *Regulation (EU) 2019/943 of the European Parliament and of the Council*

framework for early MPIs, or MPIs should be classed as their own asset within the regulatory framework. We note that MPI development requires early certainty, and we welcome the work that Ofgem and BEIS have done to date to accelerate regulatory change. This will need to continue for the enduring regime and MPI delivery in the 2030s.

Question 13: Do you have any views on the merit or necessity of defining a separate MPI asset class in UK legislation, or other legislative change? What might be the disadvantages of this approach?

13.1. For the Enduring Regime, defining a separate MPI asset class in UK legislation could be beneficial, optimising windfarm dispatch and market-to-market flows. Greater clarity is required regarding the design and operation of MPIs, as we move to a more integrated system. 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, the lack of a clear regulatory framework for near-term development and long-term operational conditions of MPIs is currently undermining the business case for these types of assets.

13.2. The current legal framework foresees separate responsibilities for ownership of connected transmission, interconnection and generation assets, and any changes to that require legal changes. It will be beneficial to consider a coordinated set of changes to legislation, licences, codes and methodologies for an enduring solution. For instance, removing conflicts in the legislation will allow one party to own and operate MPIs, saving on CAPEX and OPEX.

13.3. A simpler approach to bottom-up licence formation could be to select the required element of the interconnector and OFTO licence that allow both offshore wind transmission and market-to-market flows, a change process could be incorporated to account for more complex MPI designs. This could allow for a range of MPI options, including full MPI ownership or separate OFTO and interconnector ownership. We note that changes would need to be progressed relatively quickly to enable new MPIs under an enduring regime.

Question 14: What changes might be needed to the current UK regulatory framework to address regulatory developments in other jurisdictions?

14.1. For MPI projects, coordination between two territories' regulatory provisions is needed, which adds complexity and may therefore delay the project. The GB electricity network needs to remain compatible with the EU, in order to facilitate efficient cross-border projects. This requires partnerships with TOs, developers and government in the partner countries (both EU commission and member states), and the OTNR should make provisions for their inputs. It must also take into account the compatibility of the GB Enduring Regime with future European models.

14.2. An example of this compatibility challenge: in the EU Offshore Renewable Energy Strategy[19], the European Commission argues that to increase market and grid efficiency (and to comply with the 70%-rule), offshore generations assets in MPIs shall

[19] *EU strategy on offshore renewable energy*, European Council, 19 November 2020

be placed in separate offshore bidding zones. Establishing offshore bidding zones[20] would allow the broader allocation of congestion rents. We argue that in general the 70%-rule should not be applying to MPIs, as these serve dual functionality in comparison to classic interconnectors.

14.3. A review of the CfD will be required, to ensure that offshore wind farms connected to MPIs are still eligible for payments, or that the offshore bidding zone does not undermine the price protection offered by the CfD. We note that MPI connected windfarms require market certainty, and if their revenue allocation changed part way through the asset life (from home market to offshore bidding zone), this would have a significant impact on the investment case, under this scenario a project would need to be kept whole. Dependent on the market arrangements chosen to ensure commercial parity for offshore wind farms, the calculation methodology for setting the cap floor levels for projects may also require review.

14.4. It is important to note that we are seeing not just bilateral arrangements being potentially considered over the next two decades, but potentially multilateral market arrangements. An example of this is the energy islands[21] currently being planned in Denmark that may envisage interconnection between Denmark, Germany, the Netherlands and the UK. Consideration of future market design both in the UK and Europe, including potential offshore pricing zones, will be required.

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[20] *Market arrangements for offshore hybrid projects in the North Sea*, Publications office of the European Union, Nov 2020

[21] *Denmark's Energy Islands*, Danish Energy Agency, accessed 2021