Board of Directors:
Mary Quaney, John Bartley Doyle. Nanna Tollefsen (Norwegian)

Company Secretary:
Catherine Hawthorne

Mainstream Renewable Power Ltd
Top floor, Arena House,
Arena Road, Sandyford,
Dublin D18 V8P6,
Ireland.

t: +353 (0)1 290 2000
info@mainstreamrp.com
www.mainstreamrp.com

Mainstream Renewable Power Ltd
is registered in Ireland.
Registered Number: 453076
Registered Office:
Top Floor, Arena House,
Arena Road, Sandyford,
Dublin, D18 V8P6,
Ireland.

To: Neil Copeland
OFGEM

By email: offshore.coordination@ofgem.gov.uk

8 September 2021

Dear Sir,

Re: Consultation response to "Changes intended to bring about greater coordination in the development of offshore energy networks".

Mainstream Renewable Power ("Mainstream") is an Irish independent renewable energy developer and considered a world leader in the development of offshore wind. We have developed over 5GW of offshore wind capacity, including 25% of the UK's offshore wind plant. We are developing one of Asia's largest offshore wind farms in Vietnam, and working on offshore wind energy opportunities across Europe, Asia Pacific and on both coasts of the United States of America, United Kingdom and Ireland.

We welcome the opportunity to participate in the consultation on the "Changes intended to bring about greater coordination in the development of offshore energy networks" published on the 14 July 2021. Please refer to Attachment 1 for the responses to the consultation questions.

If you have any queries about the consultation, please do not hesitate to contact Senior Offshore Development Manager Ireland Leo Quinn at [redacted] or on mobile no. [redacted].

Yours sincerely,

Leo Quinn

Leo Quinn
Senior Offshore Development Manager

ATTACHMENT 1

Early Opportunities questions

Please note the following comments under this section, are also applicable to pathways to 2030.

Question 1: Are there any concepts we have not identified developers may wish to progress?

There is one concept to be considered that is a hybrid between the shared offshore transmission system (Figure 4) and the quasi bootstrap (Figure 5). That is where a number of projects are connecting into the same onshore substation but with separate connections, where there may still be benefits to connecting the projects offshore to reduce potential infeed loss issues or even onshore (if they are not large projects) to reduce issues with spare bays at the connecting substation. The projects may not be owned by the same developers so a level of coordination may be required to enable this.

The other concepts that have not been specifically included which should be considered by Ofgem include:

- Multi-purpose interconnector (other jurisdiction led model) where the offshore infrastructure from the other jurisdiction out to the generator is built/operated by the other Transmission Operator (TO) and the connection to GB is built by an interconnector developer.
- Multi-purpose interconnector (OFTO and other jurisdiction led model) where the offshore infrastructure from the other jurisdiction out to a generator is built by the other TO and the connection to another generator is part of an OFTO and the connection between the 2 is built by an interconnector developer.

There is also no mention of wave or tidal in this consultation document and how hybrid generators may be treated that have potential to share a connection and there is sufficient diversity in their output to make this an opportunity for optimisation of the infrastructure. This may be similar to the shared offshore transmission system concept (Figure 4) but with an optimally sized connection to shore.

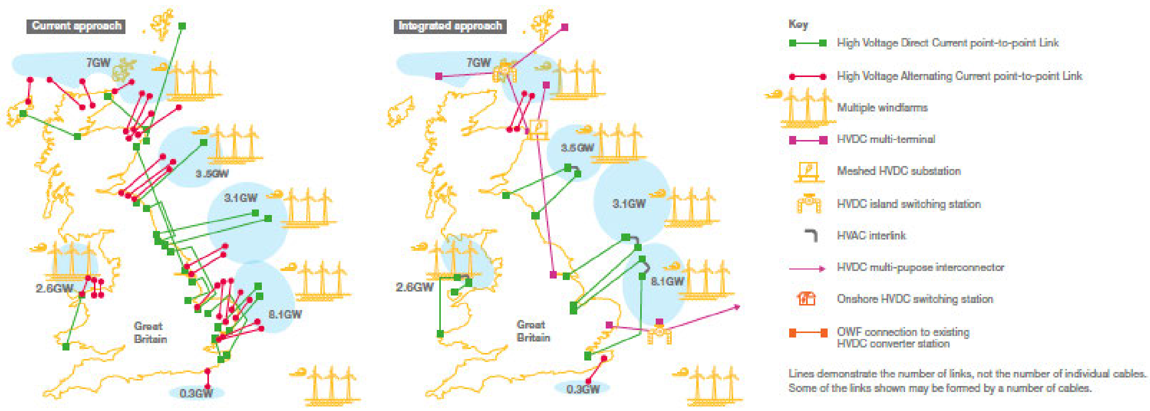
We would recommend that consideration is given to explore various scenarios where wind energy is converted to hydrogen or ammonia or other and connected via energy storage facilities or to directly serve local demand like energy centres, as the opportunities for coordination may be quite different.

It should be noted that although Concept 6 shows energy storage connected onshore to an offshore connection, our understanding of the current regulations is that they would not count as part of the same BM and coordination of those 2 entities is not currently possible even if they are owned by the same generation developer as they are physically separated by the OFTO assets owned by a separate OFTO organisation. This means that the energy storage cannot be used to efficiently reduce the impact of the offshore wind on the transmission network and the offshore wind cannot benefit from the potentially reduced wider zonal TNUoS charges onshore. To enable Concept 6 to be developed as a coordinated transmission solution then the regulations would need to be tweaked to enable settlement metering to include large energy storage facilities as part of the same BM. It is also important to enable the addition of additional facilities like this after the grid connection offer has been made, triggered or the facility is already generating. The timeframe for forming the business case and developing an onshore storage, demand or generation asset is typically much shorter than an offshore wind farm.

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

If anticipatory investment will potentially benefit developers (reducing overall transmission network charges) but also potentially benefit consumers (reducing overall bills in the long-term) then the risk should be shared. This sharing of risk will have an overall net benefit to the consumers as the developers will not have to include all of that risk in their development profile. However, the mechanisms by which anticipatory investment is carried out needs to be carefully considered to avoid social impact to vulnerable groups and further adding to the fuel poverty crisis. Companies should take on a higher percentage of the risk and it is recommended to review the distributional impacts to particular customer groups and consider policy mechanisms whereby the remaining risk can be borne by consumers with higher incomes via a taxation mechanism.

This is particularly relevant when the anticipatory investment is to enable the whole energy system to be developed economically and efficiently (to expand the wider transmission network to enable integration of other generation and demand connections). It is also very important when the offshore element of the coordinated infrastructure option (the part the developer builds and finances) is significantly more expensive initially to enable further coordination onshore or for other projects later.



For example, in the Offshore Coordination reports from NGESO some projects in East Scotland would connect to the North East of England via a combined HVDC link rather than 3 separate HVAC links to the Lothian Coast and interconnection between offshore platforms would enable the formation of a quasi-bootstrap across the B6 boundary.

Using this example, then the upfront offshore costs that they would bear between them are £2.2bn compared to £2.6bn in the status quo. But the onshore works, secured by the offshore projects, but socialised across consumers through TNUoS, would reduce from £1.0bn to £0.4bn. This brings about a CAPEX cost saving (29% ; 18% from onshore and 11% from offshore) but also reduces the number of cable landings and overall OPEX.

But assuming the developer continues with the currently preferred developer build OFTO model, one of the developers will need to build a HVDC link to the North-East ($1.1bn) rather than a HVAC link to the Lothian Coast (£0.5bn) so the risk would need to be split across not only the other developers but the consumers.

Our suggestion is that the developer (developer 1) that is building the anticipatory investment would have securities to cover the additional cost (approx. £0.6bn) put up by the other developers (developer 2 and 3) and by the TOs. The benefit to the onshore transmission system and all transmission system users (a reduction of £0.6bn) here is more than the benefit to the offshore developers (a reduction of £0.4bn) so in this example you could consider splitting the risk level accordingly - 60:40. So the TOs provide £360m in security and the other two developers £120m each. The only way that this would increase the cost to the consumer would be if the other projects do not proceed, in which case they have to pay up for their securities, not only to developer 1 but also for their onshore works (User Commitment) but this is where least worst regrets analysis will enable the regulator to determine if the risk is reasonable. This is only used as an example and if the onshore works are solely for the reinforcement of the network for the offshore wind and would not have been required otherwise then the risk and security split would need to be considered differently.

It should be noted that this only deals with the cost risk and not the development and consenting risk and timescales risk which are all very relevant when you are discussing wind projects looking to bid into the CFD regime and when you are aiming to meet carbon reduction targets.

An alternative mechanism for consideration is reducing the securities required from other developers once they have secured necessary consents in a similar way that securities are calculated for radial connections in line with the reduced risk of the project.

For overall system cost reduction another option to be considered is to examine the potential for CAPEX cost reduction.

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

It is difficult for developers to propose concepts that may mitigate an onshore constraint without input from the ESO and TOs. It is also important to understand where diversity of generation plays a part as using offshore wind assets sized for the maximum output of the generation to provide network reinforcements that are also to relieve constraints at high wind outputs may mean that the benefits are rarely realised.

The Offshore Coordination studies undertaken by NGESO identified some connections with wider system benefits, but they significantly increased the upfront costs for the developer(s). A possible solution is for the ESO / TO publish the constraints regularly (similar to the TWR) along with the costs to mitigate the constraint using the available tools to the TO and to enable developers to suggest alternatives with the appropriate additional costs required. Then, this work can be contracted by the ESO / TO the developer to be included in their works and secured as noted above.

In considering a bootstrap option, the need for investment would be within the remit of NGESO to deliver with inputs from the developer. There would be some benefit in considering a holistic approach whereby detailed design (and cost) is undertaken by single entity. Potentially this could be a new body.

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

The connection agreement with NGESO requires User Commitment for the onshore connection costs and this could be extended to other assets that are being built by others under a very similar arrangement. It should not be just at the point of asset transfer but all the way through the project development from planning and design to construction and commissioning. Other options for evidence include land lease agreements.

Options for offshore projects could include provision of evidence from The Crown Estate of progression to an agreement for lease.

Considerations could be given to a long-term holistic approach with a single architect and how demonstration of expectations to connect would work.

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

Whilst we agree with some of the principles (not all) proposed in the consultation, we do not believe that this consultation has removed any barriers that there have been to coordination on the Early Opportunities. Anticipatory Investment was always an option, as was providing connections with WNBI but these were to be assessed on a case-by-case basis and it was never clear how the costs would be recovered. Often the beneficiary of the coordination was not the first mover developer, but second movers or wider consumers and it actually made the first mover developer's project more expensive, riskier and potentially with longer timeframes. We also would have serious concerns on co-ordination as a requirement for CfD eligibility. With competition for CFDs and larger projects being developed, there will be even more desire for a developer to achieve FID before other projects and use the full capacity of a potential link to deliver their project. BEIS and Ofgem need to consider how individual project specifications can be shared, without undue influence on competitors bidding strategies.

Ofgem and BEIS should note that for these Early Opportunity projects, one of the reasons that they are seeking multiple radial HVAC connections is not related to co-ordination but due to supply chain and delivery issues with HVDC. Many of the German HVDC projects were delivered over budget, late or both, and hence the current driver for HVAC connections.

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

There are a number of changes that can be achieved through amendments to the existing codes which would not necessitate a Significant Code Review. To ensure the code amendments are made in a timely manner we would recommend a dedicated resource is identified within the ESO.

As there is already anticipatory investment risk is shared with consumers onshore and that a level of transmission costs from offshore projects are shared with consumers, the allocation of AI risk and policy to manage social impact belongs to a wider group of Government stakeholders and is outside of the Significant Code Review.

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

In the case of Early opportunities, there is a risk that changes required to facilitate offshore wind and transmission (e.g., SQSS, STC, BSC, Grid code) may not be able to be made in the timeframe required, and as such, derogations as a short-term solution, are likely to be the best route forward. Historically there have been issues from clear interpretation of the SQSS rules for HVDC connections larger than 1320MW (infrequent infeed loss). This will be incredibly important as projects grow in capacity or if multiple projects look to connect to a single link.

It should also be noted that with the MPI project options, the equivalent rules in the other jurisdiction may reduce the capacity that can be connected on a single link.

Pathway to 2030 questions

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

A clear vision and a long-term plan will result in a more coordinated, economic and efficient network and so to look out to 2030, 2040 and 2050 will definitely help but the technology and costs are changing rapidly, and the Offshore Transmission Coordination studies undertaken by NGESO seemed to miss one key aspects – the potential for regrets. Least Worst Regrets Analysis is a process used in many large infrastructure decisions making areas but it seems to be missing from this study.

Some clarity would be appreciated on the following points:

- Will the HND incorporate the interconnector work in the Network options assessment (NOA)?
- How will a HND evolve and change as leasing rounds progress?
- How will UK targets (E.g., 40GW by 2030 and 75GW by 2050 for Offshore Wind) being considered?
- Will it be regularly reviewed and follow a process similar to the NOA?
- How will that fit with the actual TEC register and queue?
- How will the HND approach work with neighbouring energy systems and consider developments in other jurisdictions, for example, Ireland and continental Europe. There is a degree of co-ordination with other countries to be further considered and clarified.
- If the HND identifies MPIs, how will those be taken forward? Will it need to follow one of the Options in the Pathway to 2030 or could an interconnector developer bid to design, build and operate it?

There seems to be a disconnect between what is in the FES and what actually is happening and there can be a year delay in the NOA catching up. If we are going to deliver the targets, then this delay may be a barrier but if the HND only includes the current contracted projects it will not achieve an optimal design but if it assumes that all leased projects will go ahead as they are then it could also create some regret.

It is unclear as to how the HND will demonstrate an economic and efficient design and get sign-off to proceed in the timescales that will be required. In the case of the Western Isles link, there was significant delay caused because there was concern about stranded assets for a coordinated connection of a number of developments that needed to demonstrate a reasonable expectation that they would connect to the system. It would be helpful to understand the lessons learned from the Western Isles link and how this has feed into the HND approach to mitigate against delays.

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

It is unclear in the consultation as to how this planned work is different from the delivery of network assets as discussed in 3.33? Is it a pre-cursor?

The responsibility for the offshore network design requires further clarity to meet 2030 targets and this requires a clear plan from Government and Ofgem. The existing TO's appear well placed for onshore delivery and 2030.

If the final solution results in two parties carrying out the work, there cannot be a disconnect between the two parties and it is suggested to propose a policy to force a JV-type partnership to ensure plans are discussed and agreed between the two parties.

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

Mainstream believe that the organisation that is to build the assets is best to undertake detailed design for assets located offshore. In some cases, this may be the generator following the anticipatory investment model discussed in the early opportunities section; and in other cases, it may be an independent offshore transmission developer / contractor selected to undertake the work.

A single architect approach where one body is responsible for the overall design could be considered as an option to address disconnect issues.

Prevention of impacts to future projects on bootstraps needs to be considered in the overall approach. Consideration should be given to Detailed Network Design (DND) requirements and how to accommodate them in the process. Particularly, for 2030 delivery, there are only a few companies with experience in DND and offshore construction. As a result, the option for detailed design should be accommodated within the process, allowing the organisation/company that is building the assets, including the offshore wind farms, to participate.

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

Yes, the existing developer led model should be retained as it allows for management of risk and this aligns with Ofgem's view that the risk should lie with the one best able to manage it.

Mainstream also request that consideration be given for shared connections offshore that could also be developer led.

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

Option 1 & 2

The main disadvantage of these options is that TOs are often slower than private developers in their development and construction works. They are less incentivised to deliver on time as it is not their generator that is waiting for connection. It is also the case that the HVDC links that have been built by TOs to date have been incredibly expensive compared to generator-led builds. There are also concerns related to resourcing within the existing TO's due to the amount of onshore work being delivered. Option 1 could potentially be seen as anti-competitive due to the reliance on existing monopolies.

Options 3 & 4

These options entail more risk whereby the detailed network design and pre-construction is to be undertaken by a different entity than the one that is going to construct it. The TO will not be able to de-risk the construction and so this will lead to additional costs. There are supply chain engagement, legal, and administrative timeframe considerations to be addressed which could cause delays if efficient processes and co-ordination are not in place and result in escalation of costs.

Option 5 & 6

These options seem to be the most favourable of options outlined and BEIS and Ofgem need to consider whether there can be coordination between the generators (who have the most experience of designing and building these assets efficiently) and OFTOs (who need to build this capability) at this stage when there are strict competition clauses to maintain.

Regarding Option 6, the generator taking responsibility may not wish to take on the wider offshore infrastructure sections and prioritises their own project. Further clarity is required on what mechanisms can be used to incentivise the scenario where other generators are considered as part of a wider TO network plan; which could incorporate such aspects as Battery Energy Storage Systems (BESS), Grid Enhancing Technologies (GETs) or otherwise. If a developer's project falls away, (for reasons such as there being no CfD) whose responsibility is it to take the offshore transmission work forward? In this case, a forced JV-type partnership makes the most sense.

General Comments

It would be useful to see further work undertaken on the options presented in the form of an impact assessment and a case presented for each option.

Competition and innovation to reduce costs: Co-ordination is requested with BEIS to review the UK Innovation strategy and ensure the grid infrastructure sector is adequately captured within the UK Innovation strategy[1] and via the Catapult network.

On a wider note, the transfer of knowledge to upskill within the sector to support competition and innovation requires consideration within the current policy framework to address information diffusion and capacity building.

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

A variation of option 6 could see a JV set up between the OFTO and multiple generators to undertake the design and build prior to transfer to the OFTO after commissioning.

Note – there was no question about the charging section in 3.73 – 3.77, but given that this is relation to Pathway to 2030 projects that are about to start development and consenting (and so grid connection options will be defined in the next couple of years), an SCR and complete change in the way charging works could impact on some of the decisions being made ,and particularly in Scotland, cause perverse behaviours as multiple HVDC bootstraps drive the onshore TNUoS charges even higher and developers have to search for alternative connection options. Mainstream request that Ofgem ask NGESO to progress these Offshore Coordinated Transmission studies to determine how each of the zones' charges would be impacted with the Counterfactual and the Integrated options to enable developers to understand how the overall cost reductions will impact their bills.

In the longer term, there could be potential scope for a third party, i.e., a transmission developer to come into the market to design and construct offshore transmission assets, but not own them, which would bring competition and diversity into the market. Several variations of a third-party model could be further examined.

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

As noted in our answer to Q1, the other concepts that have not been specifically included are two-fold. Firstly, an MPI (other jurisdiction led model) where the offshore infrastructure from the foreign jurisdiction out to the generator is built/operated by the foreign TO and the connection to GB is built by an interconnector developer. Secondly, an MPI (OFTO and other jurisdiction led model) where the offshore infrastructure from the foreign jurisdiction out to a generator is built by the foreign TO and the connection to a foreign generator is part of an OFTO project, with the connection between the two built by an interconnector developer.

Shared infrastructure will need to be developed and be multiple-terminal ready (Netherland's example). Incentives will also be required to ensure transmission assets can be reserved and connected into in the future by generators in a market competitive manner.

[1] UK innovation strategy (publishing.service.gov.uk)

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

Mainstream agree that the current operative legislation, ownership, and unbundling regulations provide a statutory prohibition against the same party holding an interconnector licence and an OFTO or generation licence. Classification is currently hindered by the fact that the same party cannot own and operate all the component parts of an MPI. Options to address this includes changes to legislation, limited exemptions, and joint JV structures between the OWF owner and MPI owner.

Changes to primary legislation could take a long time to enact with agreement on which parts of a project would be defined as Interconnector and which parts would be an OFTO being dependant on how it develops? Would an interconnector developer that allows a generator to connect in GB waters be required to transfer the assets between the generator and the shore to an OFTO?

As a short-term fix (< 5 years), a generator and interconnector should be able to hold the licence.

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

Further clarification is required on how access to the joint asset would be managed. Would the generator have to secure access rights, and could they sell those access rights during low wind (or high demand for access)? A worked example is provided below.

If considering a windfarm in the UK being part of an interconnector to EU/elsewhere, consider a radial connection cost of (£X or £1bn), an interconnector (£Y or £1.5bn) and an MPI (£Z or £2bn).

Consideration could be given to the cost saving (£X+£Y-£Z or £0.5bn) to be shared between the Interconnector and the Generator assuming they both have the same capacity. So, the Interconnector pays £Y-(£X+£Y-£Z)/2 or £1.25bn and the Generator pays £X-(£X+£Y-£Z)/2 or £0.75bn. The Generator portion is then treated as an OFTO asset and paid for as TNUoS.

But what happens if the MPI connection capacity to GB is different to the capacity to the EU/elsewhere? Or if the capacity of the interconnector is half that of the generator's rated output capacity, so that if the generator is at full output, then it exports in both directions? Or in the OFTO-led model, all the costs of the OFTO element (£1bn) are converted to TNUoS and so the interconnector only builds the additional £1bn of assets? As such, is the only beneficiary in this scenario.

The other option is that the MPI remains completely as an interconnector and the generator bids and pays for access as if the MPI connection was onshore.

Whilst we recognise that further consideration needs to be given to the way CFDs are treated, we would request co-ordination with the relevant Departments to ensure that this point is raised and given due attention.

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

Although they have different ownerships, both models are physically and technically the same. There are several points below in later questions, in more detail, relating to access and CfD to be considered.

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

General classification issues: Given the novel nature of the proposed MPI model (e.g., being both an interconnector and an offshore transmission link to OWFs) the current operative legislation, The Electricity Act 1989 (Act), does not provide a legal definition of what constitutes an MPI – but instead, as proposed, constitutes a parallel running of two licensable activities.

At this stage, the lack of a clear legal definition of an MPI makes it difficult to assess which regulatory framework and classification system would best support or hinder it; however, it appears that the initial proposal is to regulate each asset forming the MPI on a 'asset first developed' basis (i.e. an interconnector licence issued first if an IC-led project and a transmission licence issued first if OFTO-led project).

Given that the existing licence and unbundling requirements prohibit the holder of an interconnector licence from also holding a transmission licence, the indications are that the (L1) and (L2) lines would be developed by different entities (save in the case of any permitted exemptions – see our response to Q21 or derogations – see response to BEIS Question below).

Once a particular model has been selected, it may be determined that a specific MPI licensable activity is established under the Act which would require the passing of primary legislation to do so. A tailored MPI licence could be created which combines the necessary conditions from both the interconnector and transmission licences, together with any bespoke conditions which are specific to the operation of an MPI.

The concept of a stand-alone MPI licence that is suggested does raise some questions in respect of the design of an enduring MPI regime and the ownership of the constituent parts of the MPI – not least in respect of the extant unbundling requirements.

There is some inconsistency in the proposals made in the OTNR consultation in respect of, for example, the Anticipatory Investment proposals (which envisages that the secondary developer is likely to be a different entity to the first) which appears to be at odds with the development of an MPI licence, given that such a licence would likely only be workable if issued to a single party as licensee.

Even if an exemption to the unbundling requirements were to apply, we consider any form of hybrid licence model where more than one licensee is a party to be complex, likely difficult to administer and would increase risk if there were, for example, cross-termination rights.

Considerations in respect of the (L1) connection to shore:

- **(L1) as an OFTO-led asset:** as an OFTO asset it will meet the definition of a 'transmission system' of the Act (i.e., a system consisting of (wholly or mainly) of high voltage wires and electrical plant used for the conveyance of power from a generating station to a substation, from one generating station to another or from one substation to another).
- As such, (L1) becomes part of the National Electricity Transmission System (NETS) and use of system charges may be payable to it for the use of the OFTO asset – by the OWF which is connected to it (through the TRS) and by the (L2) connected interconnector.
- **(L1) as an IC-led asset:** as an interconnector asset it will meet the definition of 'electricity interconnector of the Act (i.e., means so much of an electric line or other electrical plant is situated at a place within the jurisdiction of GB and subsists wholly or primarily for the purposes of the conveyance of electricity (whether in both directions or only one) between GB and a place within the jurisdiction of another country or territory).

As such, (L1) and (L2) will be classed as being connected to and using the NETS, will be required to pay TNUoS charges to do so and be required to provide balancing services. Further, as an interconnector, the (L1) and (L2) may avail of the cap and floor mechanism.

Notwithstanding the above, it is likely that with some MPI models, the interconnector component of the MPI may not be easily identified or distinguished from the other components.

Accession to codes and regulating (L1): we would expect that an OFTO-led project would be required to accede to the System Operator Transmission Owner Code (STC) and (L1) would be operated in accordance with it and an OFTO licence.

- If an IC-led project, we would expect it to accede to the Balancing and Settlement Code (BSC), Connection and Use of System Code (CUSC) and the Grid Code (we do not consider that projects of this type would operate at a distribution level of output) and (L1) would be operated in accordance with them and an interconnector licence.
- Changes to the Act require the passing of primary legislation to effect change to enable MPI's, and the code modification process in the short term would be beneficial, with workshops and forums arranged to receive specific feedback on modifications proposed.

Interaction between licences: the key elements of the interconnector and OFTO licence may vary based on their different regulations surrounding, for example, charging arrangements, third party access requirements and the provision of data. The different charging arrangements between the OFTO or interconnector part of an MPI compared to the current radial connections or traditional interconnectors may also constitute a barrier to developing MPIs from existing projects.

- Barriers that may prevent the line to shore (L1) being classified as either an OFTO or an interconnector while undertaking other secondary activities may vary on a case-by-case basis.
- Using the existing interconnector standard licence framework means special conditions would need to be amended on a project-specific basis. MPIs could potentially cut across several different revenue stream, including, payments for participation in the capacity market, payments from offshore wind users in the form of the TRS and congestion revenues.

- However, the current framework may not be able to clearly determine and delineate the different revenues streams generated by operating the interconnector apart from those obtained from connecting an OWF.
- For the revenues to be fairly and equitably shared between the interconnector, OFTO and OWF, the revenues streams must be clearly identified and distinguished apart from each other.

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

Clear guidance on the type of evidence required to support a licence is requested. Performance reporting would need to be both practical and proportionate and clarification on how the performance report will be used and generally, how will under-utilisation of an asset be managed.

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

Transposing obligations from one licence to another:

- We understand that Ofgem proposes, in the short-term, for separate interconnector and OFTO licences to be issued for MPIs, rather than an a bespoke MPI licence.
- The use of existing standard licence conditions and amended special conditions would require analysis on a project-specific basis, depending on the MPI model that is proposed by a developer (e.g., OFTO-led or IC-led).
- Our legal advice has been that it may be the case that certain conditions are transposed into each of the interconnector and OFTO licences for a project and “switched on” or “switched off” by Ofgem direction at key stages of the development to the operational phase of the complete MPI. For example, for an OFTO-led MPI project where the offshore transmission element is constructed before the interconnector element. In this scenario it may be useful for licence conditions which relate to the operational interface with the interconnector asset to be “switched on” within the existing offshore transmission licence at the relevant time.
- In terms of the practicality of transposing licence conditions from one licence into another, this is effectively already done by Ofgem for the purposes of the offshore transmission licences, which comprise certain sections of the standard conditions for electricity transmission, and then also include special conditions which are relevant to the specific OFTO tender round.
- A similar approach could be taken for MPIs, i.e., where the standard transmission licence conditions are supplemented with special conditions (which may be a combination of existing transmission and interconnector standard conditions additional bespoke conditions tailored for the interface between licence categories in an MPI context).

Incorporation of obligations: Examples are given below of the standard conditions in the current interconnector licence which may need to be transposed into a transmission licence for an MPI:

- Condition 5 – this condition obliges the interconnector licensee to provide certain technical and operational information to transmission and distribution licensees to ensure that the development and operation of interconnected assets is co-ordinated. Whilst this would not be relevant for the offshore transmission system in an MPI (which would be owned and operated by the MPI), it would still be relevant for any connected onshore transmission and distribution systems.
- Condition 6 – this condition requires a licensee to keep separate accounts for each of their electricity activities (i.e., interconnection, generation, transmission, distribution, and supply). This could be especially relevant for Ofgem to assess and monitor an MPI's primary and secondary activities.
- Condition 10 – this condition contains the charging methodology to apply to third party access to interconnectors. The consultation flags that third party access arrangements may need to be exempted for certain models of MPI, and this therefore may be a condition which is adapted for use in an MPI licence.
- Condition 19 – this condition contains obligations specific to the operation and development of the interconnector, including that the licensee manages electricity flows taking into account exchanges with interconnected systems and ensuring the availability of ancillary services. These obligations will also be relevant to MPIs.
- Condition 25 – this condition sets out the cap and floor regime which is applicable to interconnectors. This may be relevant to MPIs; however, we note that the consultation mentions that the ICPR is considering the suitability of the cap and floor regime for MPIs, and also notes that the availability mechanism in the OFTO framework could be used as an alternative; and
- Conditions 27 and 28 – these conditions set out how interconnector payments are determined and paid to national grid as transmission system operator and to Ofgem. We expect that these payments would also need to be paid by the operator of an MPI in relation to the interconnection asset, although these conditions may need to be adapted for MPIs.

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

Section 5 of the Electricity Act 1989 allows the Secretary of State to grant exemptions from the prohibition on carrying out certain activities without a licence. Exemptions can either be granted on a class of persons basis or an individual basis. The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001 sets out class exemptions for the activities of supply, distribution, and generation, but notably does not contain any exemptions for interconnection or transmission activities.

To the extent that an MPI was carrying out these activities, it would therefore currently need to be licensed or obtain an individual exemption from the Secretary of State under the current regulations, unless a new set of class exemptions was introduced under amended regulations in relation to interconnection and/or transmission activities.

A new exemption (whether by way of a class exemption or individual exemption) may be beneficial in the following circumstances:

- **During the construction phase where only one part of the MPI is operational**: for example, where an OFTO led MPI is being built out and only the L1 transmission cable is in use but the L2 interconnector asset is not yet fully operational. In this scenario it may be useful for any interconnector activities to be exempt for the purposes of commissioning.

- **Where the secondary activity being undertaken by the MPI is so minimal as to not merit compliance with licence requirements for that activity**: this could be where the neighbouring country takes the dispatch of any electricity generated by the OWF, and therefore transmission to the GB shore is only expected to occur infrequently, although we see the likelihood of this to be limited given the nature of the activities being undertaken; or

- **In the event that any MPI projects come online before the necessary regulatory framework (e.g. a bespoke MPI licence) has been implemented:** in this scenario exemptions could be granted for any MPIs which are developed which would prevent transmission and/or interconnection activities being in breach of licensing requirements. Conditions could be attached to any such exemptions to ensure, for example, that the relevant MPI licence was applied for once implemented, that any health and safety or reporting requirements were complied with etc.

  We believe, the granting of individual exemptions over an MPI class exemption (even if only temporary) would ensure Ofgem could keep track of the MPI projects coming on-line, which may aid in the development of a more permanent MPI licensing solution.

  The SoS is empowered under Section 5(1)(a) of the Act to grant individual exemptions from the requirement to hold a transmission licence and we would recommend the SoS consider use of this power under the Act.

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

Currently, new renewable generators cannot benefit from priority dispatch and can only be curtailed as a last resort. Unless OWF generators connecting to an MPI receive a derogation from the existing regime, they would not benefit from priority market access; however, they equally cannot be extensively or regularly curtailed off the system.

See also responses to BEIS Question 1 below.

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

We have identified the following potential challenges or risks to the establishment of MPIs:

1. **The lack of a clear legal definition:** of what constitutes an MPI at this stage makes it difficult to assess how the cap and floor regime would be applicable to it. The applicability of the cap and floor regime may vary based on the specific configuration and model of each MPI proposed.
    - Although the cap and floor regime has been adopted only for interconnectors to date, there is an argument to be made that, if an ambitious view was taken on MPI's whereby a single regime was applied for the entire MPI, the cap and floor mechanism could be established for the interconnector and OFTO assets; this would require all involved parties, both developers and regulators, to work together to achieve this.

- Ofgem's regulatory jurisdiction is limited only to the part of the interconnector located within GB's jurisdiction. Therefore, the cap and floor regime may only apply to the half of the interconnector that falls within GB waters, whilst revenues over the remaining portion are regulated separately by the other jurisdiction's regulatory authority. It is unclear how this will be managed between jurisdictions such as GB and Ireland, and GB and continental Europe.

2. **Domestic/EU/third nation: Cooperation and regulatory alignment:** to deliver an attractive and cohesive policy on MPIs the UK regulatory regime must be aligned with and/or complementary to the connected regulatory regimes (EU or otherwise).
    - This can only be achieved through a joint-political and regulatory will to align arrangements for electricity regulation and cross border trade. Following the UK's departure from the EU, the UK is no longer a member of the North Seas Energy Cooperation forum; however, the EU–UK Trade and Cooperation Agreement (TCA) commits the UK and EU to create a specific forum to discuss offshore grid development and to cooperate in the delivery of development of offshore renewable energy.
    - The TCA, and any intergovernmental agreements – whether with an EU state or otherwise – to cooperate on specific MPI projects, will require a clear commitment on on-going regulatory alignment in order to deliver the correct market signals to developers (for example, in respect of delivering derogations or changes to established policies i.e., treatment of unbundling, third party access, priority access etc.).

3. **Domestic/EU: Market arrangements:** following the UK's departure from the EU, GB no longer has access to single-day coupling and intraday market coupling arrangements with the EU, resulting in the loss of implicit trading across interconnectors (save in respect of GB-Ireland interconnection).
    - The resulting use of explicit trading arrangements with continental Europe creates inefficiencies as capacity is auctioned separately to the electrical energy. The TCA contains a commitment to develop procedures to reintroduce implicit trading through multi-region loose volume coupling (MRLVC) to increase efficiency through price coupling and Ofgem and ENTSO-E are in engaged in the process to do so.
    - That said, the outcome of this workstream remains uncertain, although a successful outturn would positively impact the efficient delivery of electricity across an MPI and further strengthen the business case for potential developers.
    - Further proposals have been made regarding the implementation of a dedicated Offshore Bidding Zone concept which would allow OWFs to bid independently in energy markets of the countries hosting an MPI; however, it is acknowledged that the timescales and levels of regulatory change needed to implement a bidding zone are not likely to capture Early Opportunity projects. We recommend an immediate focus on regulatory change in order for 2030 delivery.
    - OWFs connected to an MPI, will need to assess whether there are sufficient advantages to being a position to be able to dispatch otherwise than to the 'home market'. As noted below, without changes to the CfD regime, OWFs may need to be developed as merchant projects or review opportunities for a corporate PPA, if an Offshore Bidding Zone concept is adopted.

4. **Domestic: Market solution impact on CfD support:** if an 'Offshore Bidding Zone' concept is adopted or the ability to dispatch to a third country (i.e., not GB), consideration will be required by BEIS/Ofgem

to assess the potential impacts on the CfD regime, in particular the requirement to deliver power produced to the GB market in order to avail of the CfD support mechanism.

- It is questionable whether the ability for an OWF to trade into third-party markets could be considered consistent with the underlying regulatory basis of the regime and Ofgem's statutory obligations to protect the consumer, who fund it.

5. **Domestic/EU: Priority dispatch:**
    - Currently, new renewable generators cannot benefit from priority dispatch and can only be curtailed as a last resort. Unless OWF generators connecting to an MPI receive a derogation from the existing regime, they would not benefit from priority market access; however, they equally cannot be extensively or regularly curtailed off the system.

6. **EU: Derogations Third Party access and Unbundling Requirements:** it may be considered advantageous to seek derogations from Third party access requirements and unbundling requirements.
    - Currently, ownership and unbundling regulations provide a statutory prohibition against the same party holding an interconnector licence and an OFTO or generation licence. Classification is currently hindered by the fact that the same party cannot own and operate all the component parts of an MPI. It has been suggested that the delivery of MPIs could be incorporated joint venture (IJV) structures between the prospective OWF owner and MPI owner in order to best manage the risks during the development and construction phases of the MPI and offshore wind project.
    - This may be achieved through a limited exemption to the unbundling requirements (e.g., as the generator commissioning clause operates for OFTOs currently) to encourage OWF 'buy-in' to the regime through ensuring that the technical specifications of the OFTO link are consistent with the operational requirements of the OWF (as is the case under the generator build radial link regime currently in place). On the other hand, exemptions from unbundling requirements could be considered to reduce the need for coordination between multiple parties and ensure the efficient and timely delivery of early MPI projects.
    - An exemption to the Third-Party access regime may also be advantageous to ensure that future connections to an MPI are not required to be accommodated in order to protect the OWF and interconnector enduring unconstrainted availability to transmit their power.

7. **EU: Requirements on transmission capacity:** Article 16(8) of the Electricity Regulation requires that at least 70% of the total interconnected capacity must be made available for cross border trades.
    - As such, this presents a clear obstacle for the connection of one or more OWFs to an MPI under an IC-led model, unless the regime is flexed to give OWF developers the comfort that their route to market through the transmission infrastructure would not be adversely affected. It is worth note that the same capacity restriction does not apply in respect of power transmitted to the UK 'home market'.
    - It would be useful to understand if there will be some form of some commitment of 'firmness' through priority dispatch and exemptions from TPA obligations, which could be necessary to ensure that the required transmission capacity of an MPI is reserved to the OWFs that connect to it.