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

Dear Cher-Rae, Viljami, Richard

Revised Minded-to Decision and further consultation on delivery models in Pathway to 2030

We welcome the opportunity to respond to this further consultation on delivery models for Pathway to 2030 (PT2030) projects.

Please note that this response represents the views of SSE Renewables (SSER); separate responses have been submitted by SSEN Transmission and Ossian, a joint venture between SSER, Marubeni, and Copenhagen Infrastructure Partners (CIP).

SSER is the UK and Ireland's clean energy champion with plans to expand globally to deliver the green energy the world needs. Its strategy is to lead the transition to a Net Zero future through the world-class development, construction, and operation of renewable energy assets.

SSER is part of SSE plc, a UK-listed integrated energy group investing £12.5bn between 2021 and 2026, or £7m a day, to deliver a Net Zero Acceleration Program to address climate change head on. This includes plans by SSER to double its installed renewable energy capacity to 8GW by 2026 and ambitious targets to treble capacity to over 13GW by 2031, increasing output fivefold to over 50TWh annually – enough to power around 20 million homes each year.

Aside from projects already under construction, SSER is currently developing over 10GW of offshore wind capacity in Great Britain, including two projects with a direct interest in this consultation: Gatroben (a joint venture with Equinor), which is included in the Holistic Network Design (HND) published by the ESO in July 2022, and Ossian (a joint venture with Marubeni and CIP), which will be included in the HND Follow-Up Exercise (HND FUE) due to be published in March 2023.

SSER supports the objective of the Offshore Transmission Network Review (OTNR) to deliver future connections for offshore wind in a more coordinated way, whilst ensuring an appropriate balance between environmental, social, and economic costs and wider considerations.

Within the OTNR, the PT2030 workstream aims to deliver by 2030 the transmission infrastructure required to connect HND and HND FUE projects and meet the Government's target of 50GW of

connected offshore wind capacity before the end of the decade. To meet these goals, we encourage Ofgem to adopt a pragmatic mindset in addressing certain coordination challenges – it may not be possible to achieve perfect coordination without risking compromising the achievement of the government’s 50GW target.

In principle, we agree with:

- the proposed introduction of a late competition OFTO build model in addition to the very late competition generator build model (Question 1);
- the extension of the Anticipatory Investment (AI) policy being developed for Early Opportunities projects to also include PT2030 projects (Question 2); and
- the charging principles for a coordinated offshore infrastructure set out in Appendix 1 of the consultation document (Question 3).

In Appendix 1 of our response, we provide detailed responses to the three consultation questions. We outline some of the key challenges that might impact the implementation of Ofgem’s minded-to decisions and proposed charging principles. We also propose ways in which these challenges could be overcome.

Broader considerations and proposals on the wider challenges of developer coordination and anticipatory investment can be found in our responses to Ofgem’s previous consultations, particularly:

- Consultation on Minded-to Decision on Anticipatory Investment and Implementation of Policy Changes (April 2022); and
- Minded-to Decision and further consultation on Pathway to 2030 (May 2022).

In addition to providing detailed responses to the three consultation questions in Appendix 1, **we would stress the importance of addressing promptly an overarching issue: clarity over who is responsible for delivering each non-radial offshore asset and how this party is to be selected.** This issue is relevant to both the generator build and OFTO build delivery models as well as the adoption of an AI policy.

Clarity is also required on who is responsible for developing, constructing, and operating the offshore connection points and associated platforms identified in the HND at the intersection between lines with different asset classifications (and, therefore, different delivery models and responsible parties), and where the resultant interface boundaries lie.

We encourage Ofgem to provide clarity as soon as possible, including if these are matters on which Ofgem does *not* intend to make a decision and instead leave it to developers to agree in the first instance. Transparency in this regard will enable relevant developers to proceed at pace with the delivery of all HND and HNDfUE projects.

In Ofgem’s asset classification decision published in October 2022, transmission assets included in the HND were classified into one of three categories: onshore, radial offshore, or non-radial offshore.

For onshore assets, the October 2022 decision confirmed the delivery model (TO build) and a subsequent ASTI publication in December 2022 confirmed the names of the TOs responsible for delivering each asset classified as onshore.

For radial offshore assets, the October 2022 decision confirmed that the existing OFTO regulatory regime will continue to apply in its current form. Each offshore wind farm developer connecting radially will be responsible for delivering its own transmission asset (under the generator build model) or, alternatively, for deciding that an OFTO should be appointed ahead of construction to deliver this asset (under the OFTO build model).

Therefore, for assets classified as either onshore or radial offshore, there is only one party responsible for delivering each asset, and clarity over who that party is. On the contrary, non-radial offshore assets (i.e., assets that will be used to export power generated by two or more offshore wind farms and potentially also to reinforce the onshore network) will require coordination between at least two parties and possibly more (including both wind farm developers and potentially TOs).

For non-radial offshore assets, more clarity is required from Ofgem as soon as possible on how a leading developer will be selected and what regulatory mechanisms will be developed to facilitate coordination, resolve disputes between developers, and protect the interests of both leading and non-leading developers.

The following table outlines some of the key outstanding questions and our proposals on what we think the answers to those questions should be. Where we propose that Ofgem should be responsible for certain functions, Ofgem might decide that another party (for example, the ESO) is better placed and should be responsible for those functions. Either way, Ofgem should provide clarity over who would be responsible for each specific function.

Questions	SSER's proposals
Who will be responsible for selecting the leading developer for each non-radial asset?	<p>First, relevant developers should be responsible for engaging with each other to attempt to reach an agreement on who will take on the role of leading developer (within a reasonable timeframe agreed with Ofgem).</p> <p>Then, if developers failed to reach an agreement within this timeframe, they could make their respective cases to Ofgem, so that a final determination could be made in a timely way by Ofgem to avoid further delays.</p>
On what basis would Ofgem select a leading developer, if required?	Ofgem should develop a process for selecting a leading developer in case of disagreement, based on a set of clear and transparent criteria (for example, relevant criteria may include, but not be limited to: size, location, and development stage of the relevant projects; experience and track record of the relevant developers; routes to shore available to each project

	<p>and developer under the HND/HNDFUE design and asset classification of those routes).</p> <p>This process should also include engagement between Ofgem and the developers involved – developers should be responsible for making their case, and Ofgem should have the opportunity to ask further questions where required in order to make an informed decision.</p> <p>Ofgem should aim to develop such a process as soon as possible to be ready to step in and reach a quick resolution, if required.</p>
Who will be responsible for selecting the delivery model for each non-radial asset?	<p>First, relevant developers should be responsible for engaging with each other to attempt to reach an agreement on the preferred delivery model (within a reasonable timeframe agreed with Ofgem).</p> <p>If developers failed to reach an agreement within this timeframe, as suggested in relation to the selection of the leading developer, parties could make their case to Ofgem for a final determination.</p> <p>For PT2030 projects, due to the challenges and risk of delays associated with the OFTO build model (as outline in our response to Question 1), Ofgem should select the generator build model combined with the adoption of the AI policy, with the leading developer acting as the initial user responsible for delivering the required shared infrastructure.</p> <p>For later projects in the Future Frameworks OTNR workstream, Ofgem should be able to consider selecting either delivery model, once the tender and cost assessment processes and documentation required to enable the OFTO build delivery model have been fully developed.</p>
Once leading developer and delivery model have been selected, who will be responsible for resolving any further disagreements between developers?	<p>For each potential matter of dispute, Ofgem should provide ex-ante clarity on what party (Ofgem or the ESO) would be responsible for resolving such disputes.</p> <p>Then, where required, Ofgem or the ESO (depending on the matter of dispute) should act as a mediator between developers to resolve any disputes that might impact and delay the development, consenting, and construction of the asset.</p> <p>Ofgem (or the ESO, if Ofgem decides this is the relevant party for this purpose) should also act as a central holder of relevant project information to minimise direct sharing of confidential information between developers, in order to preserve a level playing field between competing projects (for example, in CfD auctions and supply chain procurement).</p>

<p>How will Ofgem ensure that, ultimately, the required shared infrastructure gets built, and that the interests of both leading and non-leading developers are protected?</p>	<p>Ofgem's final AI policy decisions published in October 2022 focus on the need to protect the leading developer (initial user) from the risk that one or more non-leading developers (later users) might connect later than anticipated, connect with a reduced capacity, or fail to reach FID and therefore never connect. This is done by allocating the risks and costs of undertaking AI on behalf of later users to consumers until the moment later users connect and start paying TNUoS charges (or potentially permanently, if later users never connect, net of any user commitment liabilities recovered from the later users).</p> <p>In developing its AI policy further, Ofgem should ensure that the policy focuses also on the need to protect later users from the risk that the initial user might be late in delivering the required shared infrastructure; deliver infrastructure that fails to meet the required specifications; or fail to reach FID, losing any incentive to build the shared infrastructure, and potentially leaving the later users stranded.</p> <p>To achieve this, Ofgem should develop a process that allows any willing later user to step into the role vacated by the leading developer to progress the development and construction of the required shared infrastructure. Further detail on this has been provided in response to Question 2.</p>
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We look forward to continuing our engagement with Ofgem on the development of a framework for offshore coordination that enables the industry to meet the Government' target of 50GW of connected offshore wind capacity by 2030.

We would welcome the opportunity to discuss further with Ofgem the content of our response in a follow-up meeting.

Yours sincerely,

Martin Namor

Senior Regulation Manager, Renewables

Appendix 1 – Detailed responses to consultation questions

Question 1: Do you support the introduction of a late competition OFTO build model for non-radial offshore transmission assets?

In principle, we support the introduction of a late competition OFTO build model for non-radial offshore transmission assets, provided offshore wind farm developers retain the ability to select their preferred delivery model between generator build and OFTO build, as is currently the case for radial connections.

If developers can select their preferred delivery model, adding OFTO build alongside generator build provides developers with an alternative option to use at their discretion, and only where they consider it appropriate.

Allowing developers to use either a generator build or OFTO build model would also align the regulatory treatment of non-radial offshore assets to that of radial offshore assets, where both delivery models are available under the existing OFTO regime for radial connections.

However, whilst with radial connections there is only one offshore wind developer involved, with non-radial assets there will be two or more parties involved (including two or more offshore wind developers and potentially also TOs); these parties might disagree on the most appropriate delivery model to use; therefore, Ofgem should establish a mechanism to facilitate coordination and resolve disagreements between parties.

We also note that, whilst OFTO build has been available to developers connecting radially since the introduction of the enduring OFTO regime in 2014 (for Tender Round 3 and all subsequent tender rounds), so far this delivery model has not been used for any of the 18 projects gone or going through Ofgem's tender process between TR3 and TR10.

Therefore, whilst available in theory, the OFTO build model has never been used in practice and is untested. As acknowledged in the consultation document, Ofgem "*will need to further develop the process for the late competition OFTO build model, including the tender process and associated tender guidance and cost assessment documents*".

Running a tender and cost assessment exercise for an asset that has yet to be built would differ significantly from doing it for an asset that has already been built. It will therefore be important that careful thought is given to the design of a new tender process and documentation, as well as a cost assessment process and guidance – this is likely to take a substantial amount of time and effort.

After developing the required process and documentation, running a tender would require additional time and resources. The existing tender process for radial connections takes around two years from the start of the enhanced pre-qualification stage to the preferred bidder reaching financial close. We would anticipate a tender process for unbuilt assets would take at least as long, if not longer.

Using the OFTO build model for the non-radial offshore assets included in the HND and HND FUE could cause delays to these projects and risk compromising the ultimate objective of PT2030, which is to enable all projects involved to connect by 2030 to contribute towards the Government's target of 50GW of offshore wind capacity by the end of the decade.

In the consultation document, one of the reasons provided by Ofgem to justify the addition of the OFTO build model is that “*due to the number of non-radial assets identified in the HND, there is less delay risk (...) than first anticipated*”. Whilst it is true that only 3 of the 21 transmission assets in the HND have been classified as non-radial offshore, others could follow depending on the exact design of the HND FUE, due to be published by the ESO in March 2023.

More importantly, even if non-radial offshore assets represent only a small proportion of the whole HND and HND FUE, any delays should be avoided where possible, to enable all projects to connect by 2030 and contribute towards achieving the Government’s 50GW target.

Beside the risk of delays, the existing generator build model is tried and tested – it has been used for ten tender rounds and 31 projects. A new OFTO-build model would be unfamiliar, and might generate uncertainty and deter potential bidders, make it more difficult and expensive for them to raise finance, and ultimately result in higher costs being passed on to consumers.

Therefore, whilst we agree with the principle that, going forward, the suite of delivery models available to the developers of both radial and non-radial offshore transmission assets should include both the very late competition generator build model and the late competition OFTO build model, the OFTO build model should only be used where the relevant offshore wind developers all agree on the choice of this delivery model over the generator build model.

Considering both lack of precedent in the OFTO regime for radial connections and criticality of avoiding delays on the path towards achieving the 2030 offshore wind target, we consider it likely that the generator build model will continue to be preferred to the OFTO build model for most, possibly all, Pathway to 2030 projects.

Therefore, in order to effectively prioritise and assign its resources, Ofgem should only allocate resources to the development of the required tender and cost assessment processes reactively, if one or more developers indicate that they wish to use the OFTO build model to deliver their HND or HND FUE project. Otherwise, resources should be focused on resolving the more critical issues outlined in the main section of our consultation response, particularly in relation to facilitating coordination and resolving disputes among developers, including through the development of a suitable anticipatory investment framework, as explained also in our response to Question 2.

Q2: Do you support the extension of AI policy to the projects within the scope of the PT2030 workstream?

We support the extension of the Anticipatory Investment policy currently being developed for Early Opportunities projects to Pathway to 2030 projects, as this would provide developers with a regulatory mechanism to facilitate coordination and align the treatment of AI spend between Early Opportunities and Pathway to 2030.

However, it is important that, where relevant, the AI policy reflects the differences between these two workstreams. For example, under Early Opportunities, coordination is discretionary, and developers can select their own high-level asset design. Under PT2030, coordination is mandatory, and the high-level asset design is selected by the ESO as part of the HND or HND FUE process.

We encourage Ofgem to proceed at pace with the design and implementation of a suitable AI regulatory framework and early-stage assessment process and guidance and, in the short and medium term, prioritise this over the development of the tender process and documentation that would be required to enable an OFTO build delivery model.

This is because we consider the use of Ofgem's AI policy a more realistic and effective alternative to a purely commercial solution than the adoption of an OFTO build model, which we consider an appropriate addition to align options available to developers of radial and non-radial connections, but, in practice, to be unlikely to allow developers to meet the ultimate objectives of the PT2030 workstream, as explained in response to Question 1.

The degree of coordination and commitment required for the joint development, consenting, and construction of non-radial offshore assets is likely to require complex commercial negotiations and structures (for example, a formal joint venture rather than a simpler 'good neighbour' agreement), and there is a risk that the parties involved might fail to reach an agreement on a purely commercial basis, within a timeframe consistent with delivering the required shared infrastructure by 2030.

A well-developed AI policy could facilitate coordination between developers and the resolution of disputes arising between them. The following table summarises some of the key risks and possible mitigations. Further detail on these points has been provided in response to Ofgem's April 2022 consultation, and in bilateral discussions between SSER and Ofgem in November 2022 and January 2023.

	Risks	Mitigations
Timescales	<p>AI framework finalised too late to allow AI to be include in the design of in-flight projects</p> <p>Later users not in control of the delivery of shared assets, which could be delivered late or not to the right specifications</p>	<p>Publishing timetable to finalise development of AI framework and open application window</p> <p>Publishing timetable to conduct high-level review and subsequent detailed assessment of AI proposals</p> <p>Increasing allowed duration for construction of shared assets (reflecting additional complexity)</p>
Costs	<p>Initial user incurring AI cost disallowances, later users benefitting from lower TNUoS charges</p> <p>Uncertainty over final allocation of AI costs and TNUoS charges between initial and later users, affecting ability to price CfD bids</p>	<p>Providing clear guidance on what cost assessment principles will apply and examples of what assets and costs will be considered AI as opposed to non-AI</p> <p>Providing initial user with incentive to invest in shared infrastructure by ensuring disallowances are minimised</p>

	Potential liabilities for initial user towards later users in case of delays or performance issues	Providing clarity over liabilities for initial user and compensations to later users in case of delays or performance issues Providing confirmation that initial user will not be penalised if circumstances change beyond its control (for example, AI no longer meeting revised OTNR objectives)
Coordination	Developers accessing confidential information regarding competing projects Disputes between developers in relation to design, allocation of AI costs and cost recovery, etc.	Introducing formal coordination role for Ofgem or ESO to handle sensitive information and act as mediator in case of disputes

In addition to the points outlined in the table above, we note that the development of the AI policy to date has focused primarily on the risk that later users might connect later than expected, connect with a reduced capacity, or not connect at all to the shared infrastructure. However, the AI policy should also consider the risk that the initial user (the developer of the shared infrastructure) might fail to reach a positive final investment decision for its own generation project, losing any incentive to continue developing and building the shared infrastructure. This could potentially leave any later users stranded.

To address this scenario, the AI policy should include a mechanism allowing any willing later user step-in rights to the role of leading developer, which would allow the later user to progress the development of the required grid connection infrastructure on the same schedule as originally intended. To do this, the later user would need access to all relevant documentation already produced during the development stage and as part of the consenting process. The later user would also need novation rights to (i) all relevant contracts providing information that the project would need to rely upon; and (ii) all contracts required for the construction of the grid connection infrastructure. Any required consenting application would also need to be effectively novated from the original initial user to the later user stepping in to replace it.

Question 3: Do you agree with the proposed mechanics of charging (see Appendix 1) to take account of coordinated infrastructure?

Overall, we appreciate the early thinking that Ofgem has presented, and we are broadly supportive of the proposals set out in relation to the charging arrangements for offshore coordinated infrastructure. It is critical for the industry that the charging arrangements work effectively. Achieving this will require careful analysis and close industry input and engagement. We look forward to contributing to this.

Ahead of that, we have provided our initial views, summarised at a high level below, followed by more detailed commentary in relation to the specific areas covered in Question 3.

There are some key factors that we think Ofgem should bear in mind when designing the charging framework for coordinated infrastructure.

- **The complexity of the offshore network is increasing.** Shared OFTOs, multi-purpose interconnectors (MPIs) and bootstraps, anticipatory investment, among many other models and concepts, are likely to become increasingly prominent features of the offshore network. Network charging can be complex. It has the potential to become significantly more complex in a world of coordinated offshore infrastructure.
- **The use of the network is likely to change over time.** Charges are affected by the future locational mix of generation, demand, and networks. It is difficult to predict what this mix might be in the future. This represents a risk for generation investors at a time when investment in renewable generation is critical.
- **The classification of offshore grid assets is important.** Determining which offshore assets will be classified as onshore wider, offshore local, or something else, and how that classification will change over time, is important and will impact charging arrangements.
- **Asset classification will have implications for the charging arrangements that apply to different generators.** If the charging approach is materially different for different classifications, transmission charges paid by different (competing) generators might differ significantly. Since these charges will need to be reflected in their CfD bids, asset classification might tilt the level playing field. Charges for existing generators could also be affected by new network assets that are delivered at a later stage.

Taking these factors into account, we would encourage Ofgem to consider the principles outlined below as it takes forward the development of the required charging arrangements for offshore infrastructure. While these represent SSER's view, it would be helpful for Ofgem to develop its own guiding principles for charging reform, building on the work and engagement undertaken through the TNUoS Task Force and OTNR Offshore Coordination Modification Sub-group, and then consult on these principles more broadly to give all stakeholders an opportunity to comment.

- **Ensure there is alignment between onshore and offshore networks.** It would be beneficial to consider offshore grid charging arrangements in a coordinated and holistic way. Onshore and offshore charging are inherently linked so should not be considered in isolation to avoid perverse incentives. Developing high-level principles that apply to both onshore and offshore networks would be welcome. This should be done in coordination with the work already underway as part of the TNUoS Task Force and OTNR Offshore Coordination Modification Sub-group.
- **Ensure there is alignment between short-term fixes and long-term reform.** Ofgem and the industry may wish to introduce quick fixes to charging arrangements to minimise the likelihood of undesirable outcomes in the short term, while developing a more comprehensive set of arrangements over the longer term. Although it is not possible to

anticipate what longer term reform might look like, it is important that short-term measures do not pull in an opposing direction, causing uncertainty for investors. We would be cautious of stand-alone quick fixes that may turn out not to be predictable, internally consistent, or sustainable over the life of a generation project. We believe that the set of code modifications that the ESO is due to publish shortly should be reviewed from a holistic perspective to ensure they are coherent and consistent with the high-level principles that should underpin long-term TNUoS reform.

- **Use price signals only where parties can respond.** Price signals should be applied only where parties are able to respond to them, and parties should only be exposed to those risks that they are able to control.
- **Carefully consider where proposals may pull in a different direction to other, recent decisions.** For instance, the Targeted Charging Review (TCR). While Ofgem may not wish to preclude itself from changing a previously held stance, we would encourage Ofgem to be explicit and transparent where it intends to do so to minimise uncertainty for investors.

Below we provide further feedback in relation to the specific proposals included in Appendix 1 of Ofgem's consultation document.

AI cost apportionment between users

We think it will become impractical to base charging for offshore network assets on the existing offshore local circuit methodology used in the OFTO charging regime. When the OFTO regime was designed, it was different from the existing onshore local regime and this difference could only be justified based on OFTO assets being simple single-user radial circuits. It may be possible to continue using this approach for simple offshore configurations, such as two offshore generators sharing a single radial local circuit, but this approach will become impractical over time. As we progress towards Net Zero, more complicated configurations will arise, such as meshed grids with multiple landing points, reinforcing the onshore network whilst interlinking with offshore windfarms, multi-purpose interconnectors or other assets (including demand). For these more complex configurations, it will be helpful and consistent to use, for offshore, the same principles and approaches as the existing onshore wider and onshore local charging methodologies, which were designed to apply to meshed networks.

Ofgem's suggestion, in Appendix 1, that "*there is merit to a charging framework that splits the costs of shared assets between specific users*" might risk being inconsistent with Ofgem's recent TCR SCR decision, which identified two charging purposes: (i) revenue collection, which Ofgem concluded should be charged wholly on final demand; and (ii) forward-looking charges, which should only be applied where they provide a useful forward-looking price signal. Ofgem's wording could be interpreted as suggesting that the offshore locational charge could be treated as if it were a revenue collection charge on generators, by using a principle of "allocating cost" instead of providing a useful price signal. While we recognise that Ofgem will want to remain open minded at this stage, we think

that any revision of previously established positions would have to be set out in an explicit and transparent way.

Also in Appendix 1, Ofgem suggests that the cost of shared assets should be split between users based on the capacity of their plant, rather than the capacity rating of the assets deployed. We would highlight that one potential outcome of this principle, if applied, could be that certain projects might be detrimentally affected as a result of the ESO's design. For instance, some of the ScotWind HNDfUE projects, based on the long-list design, are looking at multiple connections both to shore and to other wind farms, and in some cases, the total combined capacity of all these connections exceeds the capacity of that 'hub' wind farm. It would be unfair that a project was disadvantaged simply because NGESO selected it to act as a 'hub' location.

AI cost gap

We believe there is merit in the approach of funding the AI cost gap through the TNUoS Demand Residual (TDR) charge in the years before the later user connects. It would be unreasonable to expect the later user to pay TNUoS for the years before it connects, as it will not have been using the assets during those years.

Asking the later user to pay back to consumers the AI cost gap for the years in which they have not used the assets would not represent a useful price signal, because the later user could not take any actions to respond to it. The later user will not be able to control the initial user's construction timeline, so it would be inappropriate to expose the later user to this risk.

It will be important to review the way the local security factor is calculated for offshore local assets. There is a risk that the spare capacity built as part of an anticipatory investment might be interpreted as security for the initial user, causing the TNUoS tariff paid by the initial user to be scaled up to pay for the cost of the whole circuit capacity until the later user connects. This would not be cost-reflective. This issue should also be considered in a broader context for all offshore local charges, not just for those with AI involved.

AI where one user is a network licensee

In the case where the later user connecting is a TO, we agree that the costs not paid by the initial user should be collected through the Transmission Demand Residual. However, consideration should be given to the scenario where the later user is a demand user (such as an electrolyser).

Changes to infrastructure prior to a later user connecting

We have concerns regarding the proposal that NGESO should facilitate changes to contractual arrangements and applicable charges for the initial user in case of changes to infrastructure agreed between later user and NGESO (but not by the initial user) prior to a later user connecting. It would be detrimental to investor confidence for an initial user to be exposed to an unquantifiable risk that their assets (and charges) may change at a later date due to the needs of another user seeking to connect (as, for example, these costs will not have been included within seabed leasing or CfD bid pricing of the initial user).

We would encourage Ofgem to consider ways to mitigate this risk and would welcome further discussions on this point. A possible solution could be that any contractual changes regarding the shared infrastructure must be agreed by all parties, including the initial user.

Extension of the Main Integrated Transmission System (MITS)

We believe that the issue of rezoning and how charges should apply for an offshore MITS node requires significant analysis and should be reviewed in detail by a group of industry experts. This analysis should include the use of the offshore located NETS assets for the bulk transfer of electricity from onshore to onshore locations (such as with the proposed bootstraps on the east coast). In this context, we appreciate that NGE SO is setting up two industry working groups that will look at all offshore charging issues, with any outcome expected to be delivered through code modifications. It is also important to consider that any changes to this area should be reviewed in a joined-up way with wider TNUoS changes. Changes to offshore charging can also affect onshore tariffs so it is important that these issues are not looked at in isolation.

It will be important to consider that, due to the sunk cost nature of generation assets, changing zoning and/or the treatment of charges in a way that causes a more expensive charge that the generator cannot respond to would not represent a useful price signal. Investors would have to price the risk of this type of event occurring, increasing cost to customers through higher cost of capital and CfD strike prices.

We recognise that it is possible that a substation supporting offshore wind could act as a 'MITS Node' if multiple transmission lines were connected to it. However, due to the different design standards for offshore, it will be worth considering whether, for the purposes of charging, it may be appropriate to use a different definition of MITS for offshore. Alternatively, a different criterion for including offshore circuits in the TNUoS Transport model could be used.

If Ofgem approved a wholly new approach to calculating locational signals for meshed offshore circuits that was materially different from the existing onshore regime, this is likely to affect investor confidence, especially in relation to circuits that could (i) be charged as either onshore or offshore and switch between the two over time; or (ii) involve, in terms of offshore circuits, demand/load. This would not allow investors to accurately predict their future network charges and would create distortions to decisions regarding network and generation design.

Interaction with the €2.50/MWh annual average limit

Under Ofgem's proposal, the classification of charges and whether they fall within the exclusions for charges for "physical assets required for connection" would be determined on a case-by-case basis.

We would suggest that the new OTNR Offshore Coordination Code Modification Sub-Group should have in its Terms of Reference a requirement to consider what would be the right criteria by which a "case-by-case" assessment would be carried out.