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Our Reference FPIL230713-01

Dear Nick,

RE: response to Ofgem's "Consultation on the Regulatory Framework for Offshore Hybrid Assets: Multi Purpose Interconnectors and Non-Standard Interconnectors

Cerulean Winds ("CW") and Frontier Power ("FP") (together "CW/FP") have, jointly, been successful in securing 3 sea bed leases from an auction by Crown Estates Scotland to install floating offshore wind farms to power offshore oil and gas facilities as part of the nation's journey to Net Zero through decarbonising oil and gas production. INTOG (Innovation and Targeted Oil & Gas) leasing aims to attract investment in innovative offshore wind projects in Scottish waters, as well as help decarbonise North Sea operations.

Phase 1 of the INTOG project will see some 600 MW of floating offshore wind constructed across 3 sea bed lease areas joined together using AC offshore cables and then connected to oil and gas platforms whose operators intend to enter into power purchase agreements with CW/FP. The constellation of phase 1 offshore wind farms will be connected to the GB transmission system as demand to enable power to flow to the oil and gas facilities at those times when insufficient offshore wind generation occurs to meet the demand exhibited by the oil and gas facilities.

In subsequent phases of the project the offshore wind farms will be scaled up to c.6GW of capacity in total and these will be connected to the GB and German transmission systems to enable power to flow from the wind farms to GB or Germany and for power to flow between GB and Germany. Consequently, CW/FP believes this phase of the INTOG project firmly meets the proposed definition of an MPI set out in the consultation.

Therefore, the publication of the consultation on Multi-Purpose Interconnectors ("MPIs") is timely as it would appear to directly impact the development of the INTOG project initiated by the Crown Estates Scotland leasing competition.

Response to Consultation Questions

CW/FP response to the questions raised in this consultation are made against this background. Implementation of any regulatory framework by Ofgem should seek to compliment the already advanced initiatives of Crown Estate Scotland in accelerating decarbonisation of offshore oil and gas. Furthermore, the economies of scale this project offers through colocation of additional offshore wind should be encouraged given the potential to reduce the support costs GB consumers would otherwise be exposed to if other standalone development projects were to be favoured through the implementation of these regulatory arrangements.

Our response is set out in the subsequent sections in line with the summary question template provided as part of the consultation.

If you would like to discuss any aspect of this submission please do not hesitate to contact me at m.williams@frontierpower.biz .

This submission is not confidential.

Yours sincerely

Meurig Williams
On behalf of Cerulean Winds and Frontier Power

Response to Consultation Questions

<u>Licensing Arrangements</u>

Q1: Do you have any views on our proposal to use, when appropriate, a wider common term of an offshore hybrid asset that could apply to both: category 1 assets (non-standard interconnectors) and category 2 assets (MPIs)?

In general the wider common term of Offshore Hybrid Asset is useful and we acknowledge that a MPI as a specific arrangement occurs where a GB Offshore wind farm is connected to assets which performs the dual function of Offshore Transmission and Interconnection in GB.

The proposed developments by CW and FP includes offshore wind farms in phase 1 that will be connected to power offshore oil and gas facilities to help decarbonise oil and gas production. In subsequent phases the offshore wind farm will be increased in size and will connect to Germany and GB and each wind farm will be connected and together will comprise offshore transmission and interconnection in GB. It is crucial that Ofgem determines quickly whether this arrangement will be regulated as an MPI.

Q2: Do you have any views on our proposal to use the term of non-standard interconnectors (NSIs) for category 1 assets?

No.

Q3: Taking into account the relevance of the provisions of the Electricity Act for the type of the licence that can be granted to an applicant, do you have any views on how we propose to license the operators of category 1 assets (non-standard interconnectors) and category 2 assets (MPIs)?

Category 1 assets, No.

Category 2 assets do present a number of issues for which the detailed arrangements need to be developed. The GB offshore platform is intended to be regulated using a RAB based mechanism while the cable is intended to be operated using a narrow cap and floor arrangement and the offshore wind farm connected is intended to be treated as an Offshore Bidding Zone ("OBZ"). This creates a number of interface issues in the GB jurisdiction. For example the INTOG projects have contracted phase 1 of its offshore wind generation output to third parties and this electricity will be conveyed through offshore cables to the oil and gas platforms. Any surplus generation from subsequent expansion of the wind farms will be available for delivery to the interconnector for onward conveyance to either jurisdiction. This specific configuration and contracting arrangement is not discussed in the consultation document but it is clear that any regulatory and trading arrangements need to accommodate the Scottish flagship decarbonisation initiatives already underway. It would be unacceptable if the GB MPI regulatory framework and Energy Bill cuts across the initiatives already under way in Scotland.

<u>Regulatory Regime for MPIs and NSIs</u>

<u>Principles</u>

Q4: Do our proposed principles capture the basis upon which the OHA Pilot Regulatory Framework should be designed and developed?

Not entirely. There needs to be explicit recognition and solutions to how the INTOG assets and trading arrangements can be aligned and dealt with if the definition of MPI in the Energy Bill captures those assets within the broad scope of the MPI definition.

Response to Consultation Questions

<u>Cross-border sharing of costs and revenues</u>
Q5: How should the cost and revenue sharing boundaries of an MPI or NSI be defined?

For an MPI all assets in GB that comprise an MPI should be included within the GB regulatory framework. These include onshore cable and converters, off shore platforms in GB territory, offshore cables (AC and DC) in GB territory. Any converters, cable or other assets not in GB territory should be covered by the regulatory regime in the connecting country. We recognise that this may leave a theoretical “gap” particularly where cable spans international waters which is neither in one jurisdiction or another. In those circumstances a pragmatic approach would be to include an equal share of these costs in the GB regulatory treatment with the other part covered by the regulatory framework of the connecting country. Ultimately though this requires the agreement of the connecting country’s NRA and circumstances do exist where the socio-economic welfare between jurisdictions is not equal. Before Brexit, arrangements existed in the EU to adjust the share and costs each jurisdiction is exposed to ensuring that each jurisdiction can make a positive NPV case for increasing interconnection. This may well result in an unequal split of costs and revenues between the two regulatory regimes and ultimately this is a matter for the two NRA’s to agree.

For all other category 1 assets the same principle as for MPI should be followed except that all offshore platform costs shall, in the first instance, be allocated to the non GB cost pool and the regulatory treatment of those costs established using the principles that exist in the connecting country. Recognising that scope still exists to adjust the overall costs split between NRA’s to ensure that both jurisdictions maintain a positive NPV of socio-economic welfare.

Q6: How should costs and benefits of MPIs and NSIs be shared with connecting countries?

See the discussion in relation to our answer to question 5.

<u>Costs, revenues and risks</u>
Q7: Do you agree that the Reasonable Delay Event mechanism should also apply to MPIs and NSIs?

A mechanism that acknowledges and provides relief for delays beyond the control of the licensee should be included in the regulatory regime. As you know there are numerous hard to quantify impacts when embarking on first of a kind development projects that involve complex infrastructure constructed in hostile environments and across multiple territories that, in some cases, have specific rules to follow but in others new regulatory processes will need to be created for these new asset classes.
It is simply not tenable for projects to take all delay and cost risks associated with these risks. Therefore some relief mechanism that preserves the returns for the developers is necessary if consumers are to receive value for money and for government interconnection targets to be met.

Whether the appropriate mechanism is the Reasonable Delay Event mechanism Ofgem proposed for window 3 projects, is a matter for debate. That mechanism relies on Ofgem opining on whether circumstances that have given rise to a delay are sufficient for this relief mechanism to be triggered. At the heart of this is the notion of a target commercial operations date. Experience on window 1 and window 2 projects shows that delays frequently occur due to issues associated with the National Regulatory Authorities in the connecting jurisdiction or with the lack of supply chain capacity to make the target construction window possible or with delays by a TSO in connecting the project to the relevant grid. All of these factors need to be recognised at the outset as bona fide delay events rather than have these be subject to Ofgem opining on whether or not delays associated with these causes are eligible for the RDE mechanism to apply.

Including a presumption that those events outside the developers control will be eligible for RDE relief will shift the risk profile of development in favour of consumers by reducing the risk premium developers would otherwise be forced to seek if projects of this nature are to proceed. This is a slightly different configuration to the RDE process proposed in this consultation but is one that should be considered further.

Q8: Are there any additional risks faced by MPIs and NSIs relative to point-to-point interconnectors?

Yes – legislation to allow MPIs or NSIs to exist in GB and connecting countries is immature or missing completely. This creates a novel risk for these first of a kind projects not present for traditional point to point interconnectors in most jurisdictions.

Often it is necessary for new primary legislation to be introduced before these projects can make necessary progress towards securing the necessary consents, permits and financing. This is because at the heart of these problems are deficiencies of the incumbent legislation or regulatory frameworks. This is evident in GB where new primary legislation is needed to create a new asset class of licensed MPI or NSI before a regulatory risk reward framework can be applied. In other jurisdictions the processes to change EU Regulations or National laws has not yet begun. This will inevitably create conditions that may well cause delay.

When considering just the GB elements in isolation it is clear that the INTOG initiatives in Scotland do not neatly fit into the existing frameworks or those proposed to support MPIs; for example the consultation document makes no mention of the ability of the wind farms to trade electricity on a bilateral basis direct with end consumers. For phase 1 the power from the proposed INTOG project will be purchased directly by oil and gas operators and conveyed through wires to their facilities. These arrangements need to be recognised as subsisting and cannot therefore fall within the proposed OBZ OBZ concept. Furthermore, the presence of offshore transmission network (being both AC and DC) conveying power would appear to be captured by the MPI definition especially where expansion of the wind farms is intended to connect to GB and Germany.

Furthermore, MPI's are currently prohibited from participating in the CfD process even though the offshore wind capacity can have an equal impact on supporting capacity margins for the GB network as other offshore wind farms. This discrimination will need to be removed, which in turn will increase competition in the provision of zero Carbon power and shift the supply in favour of consumers.

These are just some of the additional risks faced by projects being developed while the legislative and regulatory arrangements are being developed which do not exist for P2P interconnectors today.

Proposed regulatory regime packages

Q9: Which of our proposed regime concepts- Pure RAB, Narrow Cap and Floor, Partial RAB or Cap and Floor with IRR, do you consider most appropriate and why?

Our preference would be for a Cap and Floor with IRR. This simply sets the cap and floor by reference to a project specific IRR over the regime and construction periods rather than using notional values. This approach will better reflect the project specific risks present in these early projects and will also align the cap and floor with the financing approach adopted. This is similar (but not the same) to what has been necessary to encourage a wider pool of finance into the interconnector sectors where the cashflows at the floor need to be guaranteed in almost all circumstances for lenders to get comfortable in providing the quantum and tenor of the debt to build these assets. In effect this has created a "bespoke" cap and floor for projects; albeit with some limited circumstances where consumers can expect to be only exposed to the cap and floor set on a notional basis. Nevertheless there are circumstances where consumers are exposed to the full amount of the higher floor set on a bespoke basis.

These more "bespoke" arrangements have been necessary to encourage a deeper pool of finance to fund these asset classes and it should be expected that similar arrangements will be necessary in these new MPI and NSI asset classes. Therefore, it could be possible to reduce complexity of the regulatory mechanics (and hence be more transparent to investors) if project specific IRR is used to set an acceptable cap and floor level to protect developers given the range of outcomes developers need to consider to take projects forward and which reflect the balance of risks between the project and consumers accordingly.

Q10: Do you agree with applying the features of a RAB regime to the offshore converter platform element of an MPI project? Is there a better form of regime for the offshore converter platform element and, if so, what would be the rationale for it?

We understand the logic of including a RAB remuneration for the offshore platform included in an MPI since it forms part of the offshore transmission network. However, when coupled with a narrow cap and floor regime on a cable it creates some interface risk between the regimes; particularly when looking at what might have caused a cable system to become unavailable. It is our preference that these interface issues are internalised by making the entire MPI subject to cap and floor so the incentive to maintain availability of capacity across all the infrastructure elements is the same.

Q11: Which of our proposed offshore hybrid asset package options is most appropriate in your view and why? Within your response consider if there are other viable options not considered here, if we can disregard any options entirely, and which options best reflect the draft principles.

Our preference is Option 4 but subject to the following adjustments:

i) The capacity of the offshore wind farm comprising part of the MPI should not include that capacity reserved for providing third party PPAs (i.e. the purpose for INTOG phase 1);

ii) The CfD payments will top up revenues from the price chieved by the OBZ (i.e. the lower of the two region prices) to the strike price;
iii) The offshore platform included within the narrow cap and floor with the cap and floor levels set based on project specific IRRs

We believe these principles (except the CfD element) are applicable also to NSIs albeit the offshore platform forming part of the asset base of the grid to which the NSI connects.

<u>Design parameters of the regime</u>

Q12: Do you agree that these regime parameters would be applicable for MPI and NSI pilot projects as described above? If not, what changes should be considered?

Yes

Q13: Should the offshore converter platform be treated differently?

Our preference is for this to be included within the same cap and floor framework as all the other assets that comprise the interconnector portion of the MPI.

Q14: What would be an appropriate availability target for MPIs and NSIs? Could a similar methodology as used for interconnectors be applied?

MPIs comprise the same broad technologies as interconnections albeit the offshore platform will be a new application of an unproven design. Therefore, it should be possible to use the standard GHD model for availability calculations of all the known elements but with an adjustment made for the offshore platform. Typically (absent an offshore platform) developers would seek availabilities above 95% although contractual guarantees achieved may be lower. Allowing for some first of a kind availability risk for the offshore platform could see availabilities in the 90 – 95% range but this will need to be corroborated by engineering analysis.

Q15: What would be an appropriate regime length for the cost recovery of the offshore converter platform? Would it be appropriate to align the regime length to the one for the cable or can it differ?

Our view is that the cost recovery needs to be aligned with the tenor of any financing. We have seen that tenors of 23 years plus a 2 year tail have been possible on other offshore projects – indeed 25 years was chosen by Ofgem for a regime duration as this was the upper end of the tenor period that may be possible to fund these assets. Therefore, our view is the regime should aim to recover the costs over 23 – 25 years rather than over the technical asset life of the equipment which is likely to be longer.

<u>Other Issues</u>

<u>Anticipatory Investment</u>

Q16: Do you support, in principle, the extension of AI policy to MPIs?

Yes – however, more clarity on stranding risk and how this risk may arise needs to be understood before any further detailed comments can be made. After all, anticipatory investment can be very efficient if future planned connections occurs but could equally be inefficient if such growth does not occur. Whilst developers will be happy to build and be remunerated for AI, it will not want to absorb any risk of stranding – particularly where such stranding risk arises due to macro economic events or regulatory changes in policy or legal changes in any GB or connected jurisdiction.

Q17: Do you support our minded-to position that AI policy should not apply to NSIs?

No – the issues are the same regardless of where the offshore wind farm is located. Laying bigger cables to accommodate growth at the outset and acquiring land for a bigger converter station at the outset is more efficient than attempting to expand capacity piecemeal later where availability of land or route corridors for new equipment may simply not be available, and if it is likely to be more expensive (per unit) and require new surveys and licensing all of which is very expensive.

Q18: Do you agree with the set of scenarios set out for simultaneous and sequential build projects, and our conclusions on where AI policy could/could not apply?

Broadly yes but they do not reflect the INTOG build out scenario – this is where initially multiple floating offshore wind farms are built and networked together and connected to offshore oil and gas platforms and a back up supply is connected to the GB grid at a suitable location. In subsequent phases the offshore wind farms are expanded and connections to GB grid (South of the Scottish to England transmission constraints) and Germany then follow and which together meets the definition of an MPI. The size of the GB connection and German connection and expanded windfarm would then need to consider AI for the purposes of efficiency as the offshore wind farm capacity grows.

Q19: Do you agree with our suggestions surrounding AI risk mitigation and assurance for MPI developers, namely extending User Commitment (or analogous) arrangements to the later user and developing a process analogous to the Early-Stage Assessment?

Yes.

Q20: Do you agree with our suggested high-level mechanisms for the recovery of AI cost from the later user, and from the consumer in the instance where the later user fails to connect or reduces the capacity of its project?

Yes

Q21: If the RAB model applies, would AI policy still be required for the assets covered by the RAB, given that the consumer would in theory cover these costs?

This is more challenging – since whichever way it is dealt with the costs will be funded by consumers – either directly through the transmission charges or through energy prices developers need to fund their investment.

<u>Ownership unbundling</u>

Q22: Do you have any views on how the ownership unbundling requirements applicable to MPI and NSI operators may influence the delivery of these assets (and/or delivery of offshore generators connected to MPI assets?

No, we have not considered this in depth at this stage but we recognise we would comply with any unbundling requirements, especially given the close interrelationship that would exist between the INTOG floating offshore wind assets and the MPI that would be created in subsequent expansion phases.

<u>Regulatory safeguards and compliance requirements for MPIs and NSIs</u>
Q23: Do you have any views as to the regulatory safeguards and compliance requirements that should apply to MPI licence holders, taking into account the dual activity (interconnection and transmission) that they will perform?

No.

Q24: Do you agree that the inclusion of a RAB as part of the regulatory regime for MPIs should be subject to appropriate safeguards, including appropriate compliance requirements? If no, please explain why. If yes, do you have any specific suggestions?

Yes

Q25: Would the regulatory safeguards as well as compliance and independence arrangements already applicable to standard interconnector licence holders constituting subsidiary companies under a single parent company be sufficient if MPI licence holders were added, as subsidiary companies, to this corporate structure? If yes, please explain why. If not, what additional safeguards should be implemented?

Yes, since these arrangements would ensure separation of decision making and prevent any commercial advantage between subsidiary and any other party in compliance with the ownership unbundling requirements.

<u>Charging</u>
Q26: Do you agree with the above principles relating to connection and onshore charges for offshore generators connecting to an MPI or NSI?

Yes, in particular an OBZ model will not endow an offshore wind farm with any priority access to the MPI or onshore transmission system and consequently TNUoS charges should not be levied on those offshore wind farms that operate under that regulatory model. Although, in respect of phase 1 of the INTOG process where the offshore wind farm delivers power directly to oil and gas facilities offshore no use of the onshore transmission system for generated power will occur. However, when the offshore wind farm is not generating the oil and gas facilities will be provided power from a dedicated offshore transmission cable as “demand” only which will connect to the GB transmission system. Consequently, phase 1 of INTOG would expect to pay demand TNUoS only in respect of the capacity and energy which flows at the metered point between the GB transmission system and the INTOG offshore network.