Feedback in response to the public consultation of the Task Force Princess Elisabeth Zone

First of all we would like to thank Elia for the efforts made during the last couple of years in investigating and advancing with the integration of new offshore wind developments in the Belgian EEZ into the electricity system. Although we often disagreed with the answers given, we especially appreciate the work done by many in dealing with all the questions we raised during the many interactions in the framework of the TF PEZ.

In this response to the public consultation of the Task Force Princess Elisabeth Zone as launched by Elia on 20th of November 2023, we would like to further elaborate on the most important elements, which require, in our opinion, some further consideration.

Summary

Our feedback in this document is organized per chapter and (sub-)section of the Elia document under consultation. In order to highlight our major concerns, we would like to summarize them first:

A flexible contract is a no-go, a firm connection is a crucial requirement for bankability reasons
Since years, BOP demands a guaranteed access to the Belgian grid and fixed connection capacities to be able to fully use the valuable wind assets in the PEZ and to produce green offshore wind power at the lowest cost for society.

A proposal for a flexible access is NOT acceptable (even if it is temporary in nature or and/or partly backed by a 2s-CfD) as it jeopardizes the bankability of the projects and as such also a timely realization of the new offshore wind developments for Belgium. This view is also shared with the four major Belgian banks active in financing offshore wind parks.

Elia has to take its responsibility in the acceleration of the energy transition by providing a firm access for all concessions from the start and within the current planning. Any curtailments resulting from grid-related constraints are to be fully remunerated, in accordance with the EU Electricity Market Regulation.

Island Design and concept
As a general remark to this section, there is not enough detailed information available yet to integrate into the design exercise of the OWF in Lot 1, even though this should be started asap to achieve the challenging deadlines proposed by the Belgian Government. A thorough technical analysis of the proposed concepts and (preliminary) designs can therefore not yet be provided. We urge Elia to start providing more details and continue to work closely with offshore wind developers to ensure that timelines remain aligned, and that all remaining technical issues get resolved in a timely manner.

Wide area network EMT simulations, if required at all, are to be performed by Elia
To be able to correctly assess the risks related to the new power system phenomena that might be introduced by the introduction of more and more invertor based resources, a series of dynamics and

harmonics studies is to be performed. The risk of the changes in the system characteristics and related adverse interactions are clear, however the responsibility for assessing different areas related to these risks should fall with the appropriate party.

Performing wide-area network EMT-based simulations, if required at all, to facilitate long-term power system planning and evaluate interactions across the Belgian high voltage network and beyond is within the responsibility of Elia as the Transmission System Operator and not for a single Customer requesting to connect.

Furthermore, the studies are proposed to continue for a long period, several years after finalisation of the wind park construction. This might introduce new issues, which can no longer be mitigated in with hardware changes, as hardware changes can no longer be considered in that stage. In the operational phase, it cannot be guaranteed that 'tuning' or 'software'-type of solutions can sufficiently mitigate the identified risks.

Proposing an Offshore Bidding Zone for the PEZ developments introduces a large number of risks and uncertainties with unknown implications; The Home Market set-up is the way forward.

BOP understands that the concept of an offshore bidding zone might provide some benefits from a market integration perspective. So far, however, the concept remains highly theoretical and comes with a large number of uncertainties on technical, regulatory and project related aspects.

Uncertainties and risk introduced by Elia as a result of the grid and market topology should not be transferred to the offshore wind producers, as it increases the risk profile of the projects which increases the offshore wind production costs and might even jeopardize the bankability and/or realization of the projects. The grid operator is the only and best party to cover these risks. A large number of implications remain unclear, introducing unnecessary risk into the project.

Given the short distance between the Princess Elisabeth island and the load centres in Belgium, the structural congestion is to be tackled to the maximum extent possible. A proportionate increase in transmission capacity is to be realized first.

When considering the introduction of an OBZ, all implications for the OWPs are to be covered. A capability-based 2-sided CfD will not suffice as the lifetime of the projects largely extends beyond the contract duration, the OBZ hinders engagements in cPPA (which might take up to 75% of the volume) and the balancing implications (f.i. a raise in ramping rate limitations and preventive curtailments) and balancing costs remain uncertain.

Balancing measures limiting offshore wind production are of last resort and to be fully remunerated in accordance with the EU Electricity Market Regulation

Balancing of the power system is to be maintained at first instance by the market and secondarily by the TSO via market-based products. BRPs are to be sufficiently incentivized to balance their portfolios, but it must remain the BRP's prerogative to choose the appropriate means to fulfil its balancing obligation. The provided incentives should foremost be market-based, technology-neutral and applied at the level of the BRP's portfolio.

The proposed measures that are asset-based, technology-specific and applied at the connection point (or for some proposed at the turbine level), are to be applied as last resort measures after reaching clear criteria and activation triggers and are to be fully remunerated in accordance with the EU Electricity Market Regulation.

General remarks

Decisions taken prior to discussions in the Task Forces

Cf. §1.3 page 14: **“Some aspects that have been discussed and concluded during the different Task Force meetings have led to decisions already made by Elia to ensure a timely delivery of the infrastructure.”**

Elia mentions that all aspects are discussed and concluded during the different Task Forces. But some decisions are already made by Elia prior to providing information in the Task Force and are no longer open to adaptions. As a result certain project risks in Elia’s design are not consulted on and can no longer be mitigated in the design of Elia.

It concerns for instance the inter array cable routing, pull-in limitations and cable crossings resulting from the design of the island scour protection, J-tubes, caissons,… which could result in significant technical challenges and cost implications for the projects connecting to the energy island.

1. Legal and regulatory framework

1.1. Appendices of the Connection Contract

Cf. §1.4.1 page 18: *"As a general comment, all the requirements that will be found in the tender connection requirements, will be translated in the appendixes of the connection contract."*

- Are changes to the appendices of the Connection Contract subject to a public consultation?

"… where needed some amendments based on what is actually installed (infrastructure, metering information, etc.) to match with the reality on field."

- To what extent can amendments be made without public consultation?

1.2. Metering at the Connection Point

Cf. §1.4.1 page 18: *"It's also worth noting that the metering will be done at the connection bay and the total injected and/or consumed energy will be the sum of all meters connected separately on each 66kV bay."*

How will the (sum of) metering on the Connection Point be matched with Ancillary Services such as the VSP which are expected to respond to a voltage input on Access Point level? To ensure a robust control in line with the compliance evaluation on Access Point, also the metering for Ancillary Services should be evaluated on aggregated level and should be able to consider the various operational situations (i.e busbar coupling open/closed on 66 kV or 220 kV level).

1.3. Proximity Agreement

The proximity agreement is not regulated. Have lessons learned from MOGI been considered and will it be consulted upon?

For MOGI, a proximity agreement was set-up as a multi-party contract (in that instance, between the 2 OWF developers and Elia, i.e. 3 parties), in order to streamline the approach, as well as the total liability *per event* to ensure it remains insurable. This approach has proven to be effective, and we would urge to use a similar, multi-party set-up, with a total liability cap to be agreed between the parties and based on feedback from the insurance market. Given the timing difference of the award of the different lots, the agreement must allow for new parties to enter at a later date.

2. Connection Requirements

2.1. Flexible connection contract is a NO-GO (§2.3.1)

Since years, BOP demands a guaranteed access to the Belgian grid and fixed connection capacities to be able to fully use the valuable wind assets in the PEZ and to produce renewable offshore wind power at the lowest cost for society.

The proposal for flexible access is NOT acceptable (even if it is temporary in nature and/or partly "backed" by a 2s-CfD) as it jeopardizes the bankability of the projects and as such also a timely realization of the new offshore wind developments for Belgium.

Elia has to take its responsibility in the acceleration of the energy transition by providing a firm access for all concessions from the start and within the current planning. Any curtailments resulting from grid-related constraints are to be fully remunerated, in accordance with the EU Electricity Market Regulation.

Elia proposes a flexible access contract to the first concession of 700MW, ending with the finalization of Boucle du Hainaut.

As a principle, uncertainties and risk introduced by Elia as a result of the grid and market topology should not be transferred to the offshore wind producers, as it increases the risk profile of the projects which increases the offshore wind production costs and might even jeopardize the realization of the projects. The grid operator is the only and best party to cover these risks, with lowest societal cost.

Foremost, a flexible access, hindering the injection of the offshore wind production due to grid constraints is not bankable and thus not acceptable at all.

This view is shared with the four major Belgian banks active in financing offshore wind parks. We would like to refer to their reaction to this public consultation and highlight the following conclusions:

- *"The introduction of non-manageable risks such as the flexible connection contract is likely to be a major blocking point for bankability. We expect this impacts bankability but also to the feasibility of the proposed carve outs with corporate ppa's and cooperative ppa's.";*
- *"As the curtailment risk cannot be controlled by the project company, the project would clearly not be bankable"*

The 2sided-CfD contract does not provide sufficient guarantees to mitigate the realisation risk, as the tender conditions allow for a carve out up to 75% of the volume (50% corporate PPA, 25% cooperative PPA). In order to correctly compensate the offshore wind parks, also for the volume under the CfD contract, it is expected from the offtaker to cover for the missed market revenues during grid-related curtailments. On top, there is a further impact on the revenues from a loss of Guarantees of Origin and implications on the imbalance costs. . As a result, there is still unacceptable exposure resulting from the flexible access.

Also, the flexible access is supposed to end upon realization of Boucle du Hainaut, but no guarantees on a realisation date can be provided before closure of the tender phase 1, because the permit procedure for Boucle du Hainaut will not be concluded. This uncertainty in time further increases the cost of the risk.

Firm access is to be provided for the offshore wind developments in the PEZ. Other EU countries with major offshore wind developments (f.i. Ireland, the Netherlands and Germany), are facing similar grid constraints and permitting issues like Belgium, but a firm access is still provided to the offshore wind parks.

2.2. Grid Infrastructure (§2.3 and §2.4)

Single node operation

Elia's ambition is a single node operation, but the stated reference at this stage is a split node operation. To avoid unnecessary cost implications and uncertainty, this reference case is to be used throughout the requirements (e.g. grid code requirements and related SCR, market design,..).

Cf. §2.4: The normal operating modes are represented, however they do not match with the statement in section 2.3 that split node operation is the reference case for the moment. In that case, a number of the busbar couplings on 220kV must be open in the normal operating mode.

Power constraints of the concessions (2.4.2)

Cf. §2.4.2: *"4) The injection for each of the 3 concessions is strictly limited to their respective capacities, as identified by the Belgian government (i.e. 700 MW, 1400 MW and 1400 MW). It is up to the respective Offshore Wind Farms to make sure these limits are continuously respected;"*

To make the most efficient use of the offshore transmission system and offshore wind farm assets, it would make more sense to evaluate if the respective capacities of the three concessions could be exceeded under certain operational conditions while at all times respecting the (dynamic) loading limits of the Elia grid assets.

A key benefit of the energy island, as presented by Elia, is to group the connection of the new developments in a single location to enable a more efficient use of the offshore transmission infrastructure.

When a neighbouring wind park is not fully using its 'allocated capacity', the remaining capacity should be maximally made available for the other wind parks in the PEZ, otherwise, grouping the connection doesn't provide the presented benefits. Therefore, both overplanting and injecting more than the 700MW / 1400MW limits presented is to be allowed, while respecting the maximum technical infeed restrictions.

Overplanting (§2.4.2)

Cf. §2.4.2: *"5) The installed capacity may exceed the maximum level of power injection (i.e. overplanting) by maximum 5%, defined at the level of the tender (i.e. 735MW, 1470MW and 1470MW)."*

Why is Elia referencing overplanting constraints? In case of overplanting limitations, this should be specified in the governmental tender requirements and not in Elia's documents. Elia should only reference injection constraints.

Final and tendered grid capacity to shore

According to Figure 14, a 3.5GW grid capacity between the PE island and the BE shore is considered (AC + DC). Is the referenced 3.5 GW grid connection capacity to shore the final capacity as tendered by Elia for the AC topsides, HVDC converters and AC & HVDC cable connections?

Spare Bays

Cf. §2.1 page 21: *"In total 40 bays will be available for 3.5 GW of wind power, as well as 5 spare bays to guarantee flexibility in windfarm design."*

Can these spare bays be considered available by Developer or does this require specific agreement from Elia before they can be considered in the design? In other words, how will the spare bays be divided over the developers and what are the criteria to use a spare bay? The use of spare bays is anyhow related to the optimization of the OWF's layout and string grouping, but what are the limits to do so?

2.3. Ventilus timing (§2.5)

The construction of Ventilus is a pre-requisite for the connection of Lot 1 of PEZ. This is a major risk for the OWF and construction cannot start if the timeline of the connection is not clarified.

In the planning shown in Figure 21 page 35 no buffer seems to be available between the end of the construction of Ventilus and the commissioning of the first wind turbines. Can Elia confirm that there is no buffer or that the construction period already includes a buffer? If so, how long is it? In the current timeline, Ventilus seems to have become the bottleneck.

Moreover, the planning shown seems to either not consider any appeal on (i) the GRUP and (ii) the Ventilus permit, or to indicate that in case of appeal(s) Elia will take the risk and start construction anyway (which may be prohibited if the appeal calls for a need for suspension). Can Elia indicate its' underlying assumptions in this timeline? Can a worst-case scenario timeline be shared? The unclarity regarding the full timeline (GRUP, permit and construction) introduces additional risks, and thus costs, that will be included in the bid pricing if not clarified in time.

2.4. Island Concept and cable routing

Operating room for OWFs (§2.6)

Will there be any space on the island (or Gezelle) to include a limited operating room for the OWFs (in view of a contingency plan for a.o. cyber security and/or in case of calamities)? This is highly recommended.

Land area (§2.6.1)

Is land area foreseen for e.g. harmonic filters or any other mitigation measures which may be identified as part of the grid compliance process?

Cable routing around the PE island (§2.7.1)

To evaluate the inter array cable routing impact, please provide a zoomed out view of Figure 25 to show the proposed cable corridors for all concessions. Especially the cable corridor connecting into Concession 1 is currently not clear (it is not shown on Figure 26). Please also share the shape-file of these cable corridors for integration into a GIS package.

Cable approach (§2.7.2)

Can Elia provide further clarification on the scour protection that is anticipated to be present? The information provided in the document is very limited. For example the Nature Inclusive Design references "chaotic scour protection" and "large boulders" around the island could be detrimental for cable installation works.

Please explain how the scour protection will be aligned with an efficient (and object free) cable routing?

Please also provide further information on the dimensions of the scour protection around the island (length from the island caissons), spacing between the J-tubes, … as requested during the Task Force meetings.

Please provide further information on the dimensions and thermal resistivity of the various materials presented in Figure 27. This area is expected to be a thermal bottle neck in the inter array cable design and may require a detailed analysis by the Developers prior to the Tender to ensure this design is compatible with the max. amount of bays imposed by Elia.

If Elia has performed studies on the thermal constraints resulting from this J-tube / caisson design, please make these available.

Routing on the PE island (§2.7.4)

Who will be responsible for the provision of the watertight cable transits through the secondary wave wall?

Several crossings appear to be present resulting from the proposed routing of the cables on the island. Please provide a clear overview of the crossings and proposed crossing design to ensure any impact on the inter array cable design can be considered.

What will be the thermal characteristics of the soil below / around the concrete culverts?

2.5. High voltage systems (§2.8)

The property and maintenance border is specified according to IEC62271-209 (which states female part is provided by the cable supplier) while the following paragraph states Elia will provide the female part. Does this mean ownership of the female part will transfer to the Developer, or will Elia retain ownership of the female part?

Will Elia provide provisions to be able to test the inter array cables prior to energisation (e.g. VLF or high voltage resonant tests), both in terms of space allocated on the island near the topside as in permission to e.g. test the cable through

- a spare bay on the Elia switchgear?
- a flange on the GIS (VT flange f.i.) where gasworks are taken care of by Elia

Or any other solution, as a test rod can't be mounted on the proposed terminations.

The single phase short-circuit current (4kA) is quite high due to the design needing to accommodate for two earthing transformers in parallel. Has the option been investigated to add disconnectors to avoid this, which would reduce the single phase short-circuit level to 2 kA?

2.6. Secondary systems

Protection systems

Will teletripping from the WTG towards the Elia switchgear be accommodated for if there is a need for e.g. backup protection on the WTGs?

The 150 ms criterion of zone two may need to be increased a bit to ensure it can be selective with the wind turbine protection system. Part of further refinement during engineering.

Signal exchange

The proposed measurement converters have a too slow response time and insufficient feature set to be compatible with the plant controller of the wind farms. A direct connection of the measurement device (e.g. Elspec) of the plant controller to CT/VTs will be required. Has Elia performed a check with WTG OEMs that their listed requirements are fulfilled for the measurement devices of the major OEMs?

Why does Elia specify lifetime and redundancy requirements for measurement converters / devices which will remain property of the wind farm developers? This should be the choice of the wind farm developer.

Elia should provide for the necessary measurement converters that fulfill the OWF requirements to establish an OWF control system that is capable to achieve grid code compliancy.

Considering compliance is evaluated at Access Point level and not at Connection Point level, is the use of summation CTs for the PPC allowed or does Elia expect the PPC to be able to regulate the individual 66 kV inter array bays to different levels?

Why is TASE2 proposed as protocol for e.g. the wind speed and wind direction signals while these are also realised in IEC104 on the existing offshore wind farms?

The "Emergency Elia“, "Blackout Elia" and "Grid Restoration Elia" signals should not be in the list of signals from the wind farm to Elia (Figure 34), or are these expected as a feedback / confirmation of receiving these signals?

The list of signals is not complete, e.g. ancillary services such as the VSP will require additional signals. Also additional interface signals are expected, such as fire alarm in the OWF room, CCTV feed in the OWF room,…

Telecom concept

Availability of space on the GEZEL onshore substation to install a telecommunications building, similar to the ones of the existing offshore wind farms next to Stevin, would be welcome.

2.7. Marine and works coordination

Access to Island (§2.10.2)

Cf. §2.10.2.2 page 52:
Why does the site-specific induction need to be created by the Contractor? It is assumed that for general access and egress, safety,… related topics, Elia will prepare a site-specific induction as well?

Training requirements (§2.10.4)

Will the Elia Electrical Training and BA4/BA5 task specific requirements apply to all works, or only to works in / near the electrical facilities? E.g. also for crane drivers responsible for lifting the concrete covers of the culverts,…?

3. Dynamic and Harmonic

3.1. Additional requirements

"Following Article 110 §2 of the Federal Grid Code, the Transmission System Operator may introduce additional requirements applicable for offshore wind farms."

The Federal Grid Code stipulates that a justification of the additional requirements from a grid perspective but also has to take into account the effect of the requirements on the offshore production units.

3.2. Appropriate party to perform the studies and simulations

The risk of the changes in the system characteristics and related adverse interactions are clear, however the responsibility for assessing different areas related to these risks should fall with the appropriate party.

An offshore wind farm can perform the necessary SMIB RMS and EMT simulations to demonstrate the performance of its assets and the compliance with the requirements of Elia. This is the internationally recognized methodology within for example ENTSO-E and CIGRE for connecting offshore wind farms to weak grids. Performing wide-area network EMT-based simulations, if required at all, to facilitate long-term power system planning and evaluate interactions across the Belgian high voltage network and beyond is within the responsibility of Elia as the Transmission System Operator and not for a single Customer requesting to connect.

This is e.g. consistent with other jurisdictions and the development of RfG2.0 where on the European scale there does not appear to be a need recognised for wide-area EMT simulations to be performed by Customers even though RfG2.0 is specifically written to account for the increased penetration of IBRs. Also looking for instance and specific TSOs, in Ireland which has a significantly weaker grid than Belgium, EirGrid is considering the need for interaction studies to be performed in areas with high penetration of IBRs, but has since confirmed that EirGrid as the TSO is the most suitable party to perform these interaction studies.

Since wide-area simulations are very complex, time consuming calculations which are prone to modelling issues related to third party black box models, which are subject to NDAs with Elia and not visible to a Customer, there is a significant risk that requesting a Customer to perform these simulations would result in very complex communication lines, delays in the grid compliance process and eventually delays in the project execution and energisation, resulting in significant costs.

Elia as the TSO is responsible for and owner of the wide-area network and has Contracts in place with each of the Customers connected to it, providing the necessary tools to evaluate interactions on a more granular level and allowing for direct identification of and communication with affected parties. Since these simulations would fit in an overall system and new connection planning, this would also allow for the more efficient execution of these works by grouping new installations which are expected to be connected in a similar timeframe in a single set of simulations.

Similar arrangements as proposed on the need for tuning of controllers and parameters based on the outcome of the wide-area simulations can be retained even if Elia performs these studies.

Elia bases the need for wide-area EMT simulations on a calculated aggregated short-circuit ratio (SCR). This aggregated SCR appears to be calculated by Elia for the single node operation which is the ambition, whereas the two-node operation is considered the reference case as indicated in earlier sections of this public consultation. As a result, also the SCR should be calculated for the reference grid operation case.

Furthermore, the SCR at a certain node in the Elia grid is the direct result of the Elia's long-term power system planning in terms of number of transmission lines, transmission voltage, transformer specifications, connection of synchronous compensators,… The resulting risk for dynamic instabilities is therefore the outcome of the planning choices made by Elia and should not be transferred in full to the compliance process of individual connections.

Finally, the conclusion of Elia that wide-area EMT simulations are required for the calculated aggregated SCR values does not seem to be supported widely by the international community.
For example, the new EU Network Code RfG2.0 does not come to the same conclusion as Elia that wide-area EMT simulations need to be performed by Customers as part of the grid compliance process. Similarly, CIGRE Technical Brochure 671, which provides guidelines for the connection of wind farms to weak grids and the related dynamic studies to be performed, does not recommend wide-area EMT simulations to be performed.

Furthermore, studies are proposed to continue, after finalization of detailed design, during the construction phase of the wind parks. In that stage, no more hardware changes can be considered. it cannot be guaranteed that 'tuning' or 'software'-type of solutions can sufficiently mitigate the identified risks.

3.3. Standard and additional requirements (§3.3)

Cf. 3.3 page 61: "Unless explicitly mentioned in the text, the requirements have been already presented and thoroughly discussed with the stakeholders during the Task Force Princess Elisabeth Zone and ad-hoc workshops meeting."

This note seems to indicate the additional requirements have been discussed and agreed on with industry. For the avoidance of doubt, this is not the case as per the remarks on Chapter 3.

3.4. Technical requirements for voltage control (§3.4)

New requirement for injection and absorption of reaction power (§3.4.1.3)

The text related to moving the area of compliance within -0.3xPnom to 0.35xPnom still requires explicit acceptance by Elia. It was understood during the Task Force that this would be allowed regardless, given the high capacitive charge of the infield cables which may require moving this window to ensure compliance. Please adapt the text.

Requirements at Access Point instead of Connection Point (§3.4)

The requirements in §3.4.1.3/3.4.2.3/3.4.4.3 still refer to meeting requirements at the Connection Point and to the PPM which is also defined at the Connection Point, while it was understood during the Task Force and is confirmed in a later section that compliance is evaluated at the Access Point. How will this be translated in the Connection Agreement, the Simulation Requirements, VSP T&Cs,...?

IEC104 protocol vs. ReVolt (§3.4.4.3)

Figure 34 refers to the IEC104 protocol for the Mvar setpoint. Will this protocol replace the ReVolt interface which is currently being used for Mvar Setpoints in the context of the VSP, or will two setpoints exist in parallel?

Remotely switch the reactive power control mode (§3.4.4.3)

How will the new requirement to allow for remote switching of the reactive power control mode affect the performance evaluation, penalty mechanism and remuneration of the VSP? Also in reactive power control mode the wind farm is delivering voltage services (depending on the Q setpoint). Will this Mvar exchange be remunerated as a manual control within the VSP framework?

It must be noted that such requirement induces new developments and cost.

3.5. Additional requirements for active power forced oscillation (§3.6)

Active and passive damping (§3.6.1)

Passive and active damping are represented as two independent designs. To be clear, it is typically a case of passive damping AND active damping which is required to keep the accelerations and forces acting on a wind turbine sufficiently damped.

Indicating the power profile of active damping in figure 54 as “Non-acceptable behaviour” is not in line with the recent proposal of Entso-e and WindEurope on this topic. Some oscillations caused by active damping are allowed.

Interarea oscillations (§3.6.1)

Has the risk for interarea oscillations been demonstrated and quantified by Elia / ENTSO-E by simulations on a European wide simulation model?

Proposal of criteria for active power forced oscillation (§3.6.3)

A range of values is mentioned in the draft ENTSO-E requirements for forced oscillations. Can Elia confirm the default limits listed will be applicable to the PEZ? Clarity on the limits is to be provided prior to tendering.
In other cases, a quantified motivation as well as a CBA should be provided. OWF technical capabilities must be respected in any case.

3.6. Technical requirements for the conformity process (§3.8)

Availability of models of future connections (§3.8.1.2 and §3.8.8)

Detailed black/grey box models of future connections are not expected to be available at the time of connection. While in theory it makes sense to include future connections in the assessments, the models to represent these assets will be based on generic models which may not be applicable under all conditions. As a result, there will be significant doubts related to the validity of the results which is a problematic basis to determine mitigation measures on.

Aggregate SCR index (§3.8.4)

The proposed aggregate SCR index seems to originate from the CIGRE TB671 "Equivalent SCR", although there is a slight difference in how the voltage dip on the two nodes is evaluated (3-phase metallic short-circuit vs small voltage difference). What is the reason for this change?

Criteria for RMS and EMT simulation requirements (§3.8.4)

The conclusions for the criteria to define the requirements for RMS and EMT simulations deviate from those of CIGRE TB671 Fig 7-16. Why are the Elia criteria more stringent than internationally recognised principles?

CIGRE recommendations:

- SCR > 5: OK to use generic models to perform stability studies
- 3 < SCR < 5: Consult with model provider and equipment manufacturer. Use detailed RMS models to do stability studies.
- SCR<3: Consult model provider and equipment manufacturer. Use manufacturer specific models. Do stability studies with EMT models. Consult with manufacturer to tune controls as necessary. Examine other mitigation measures as necessary.

Wide-area RMS and EMT based simulations are not proposed in TB671.

It should be noted that for direct connection to a collection circuit, CIGRE proposes to use SCR < 2 instead of SCR < 3 in TB671.

Modelling of SMIB network (§3.8.5)

How are the "similar type of generations connection on the same node" expected to be modelled explicitly if the related models are not expected to be available and if they are, not available to the Customer to consider?

Simulation requirements (§3.8.6/§3.8.8)

The simulation requirements should be made explicit and clear in advance of the tender. Rough estimates of scenarios and events to be considered lead to uncertainty and increased costs and project delivery risks.

Performance of collective assessment (§3.8.7)

Option 4) where Elia performs the wide-area simulations should be the default option, since these are an integral part of the responsibilities of Elia as part of the long-term power system planning. As a result and since it relates to interactions between numerous Customers and possibly even cross-border interactions, it is also not considered acceptable that the related costs are charged to individual clients as part of their Compliance Process.

Legal review of wording of the mitigation role and responsibilities (§3.8.8/§3.8.9)

Further legal review on the wording of the mitigation role and responsibilities as described by Elia is needed. The requirement for full responsibility and cost to be borne by the asset Owner for 5 years after the connection for any non-conformance resulting from new connections is not acceptable.
Also, a CBA should be performed amongst Elia assets and other committed owners to look for the most cost-effective acceptable solution.

Proposal for improved conformity assessment process (§3.8.8.2)

The proposed conformity assessment process, and especially stage 3 and 4 related to the collective conformity assessment and related mitigation process, result in significant risks for delaying project energisation and wind farm production and are not acceptable in the current form.

Stage 5A-2/5C-2: it is not possible for the PGM owner to install the required measurement devices since Elia is not allowing the PGM owner to connect measurement devices to the CT and VT on the Energy Island (ref section 2.9.2). Elia to install the necessary measurement devices on Connection / Access Point level during the compliance testing.

Stage 5B-1: the need for conducting further tests, especially those involving the wider network, as currently described is too open ended. Since this is scheduled prior to the FON in the compliance process, this poses a significant risk in blocking and delaying the FON while waiting for suitable grid conditions, completely external to and outside the control of the OWF.

Application to offshore wind farm to be connected to PEI (§3.8.9)

Why is reference made to PEZ OWFs having a 350 MW size in the context of compliance? Please confirm compliance will apply at Access Point level for the entire 700 / 1400 MW OWF as confirmed in the paragraph below and not in 350 MW blocks. Further is mentioned “and shall be connected the Elia transmission system on 66kV substation based on fully converter driven solution." ? What is the reason to only mention fully converter driven solutions? Others are forbidden?

Furthermore, please clarify:

- Is this SCR calculated for single node operation, or for the reference design case of two-node operation?
- Is this SCR calculated to be representative at 220 kV or at the 66 kV connection points of the OWFs?
- What do the HVDC_1, HVDC_2 and HVDC_3 represent? The referenced apparent power does not appear to be consistent with the HVDC converter station design?

- Has an evaluation been performed on the overall impact on the consumers resulting from these design choices?
  For example, an additional AC connection to shore would increase the export capacity to shore (assuming an adequate onshore backbone) and would increase the SCR at the offshore node, thereby reducing the risk of instability and the resulting concerns for the security of supply.

4. Market design

4.1. Grid topology and Offshore Bidding Zone (§4.1/§4.3/§4.5.4)

BOP understands that the concept of an offshore bidding zone might provide several benefits from a market integration perspective. So far, the concept remains highly theoretical and comes with a large number of uncertainties on technical, regulatory and project related aspects.

Uncertainties and risk introduced by Elia as a result of the grid and market topology should not be transferred to the offshore wind producers, as it increases the risk profile of the projects which increases the offshore wind production costs and might even jeopardize the bankability and/or realization of the projects. The grid operator is the only and best party to cover these risks. A large number of implications remain unclear, introducing unnecessary risk into the project.

Given the short distance between the PE island and the load centres in Belgium, the structural congestion is to be tackled to the maximum extent possible. A proportionate increase in transmission capacity is to be realized first.

The Home Market set-up is the way forward until <u>all</u> preconditions are satisfied after which a thorough analysis of the impact and mitigating measures to implement an OBZ can be performed.

When considering the introduction of an OBZ, all implications for the OWPs are to be covered. A capability-based 2-sided CfD will not suffice as the lifetime of the projects largely extends beyond the contract duration, the OBZ hinders engagements in cPPA (which might take up to 75% of the volume) and the balancing implications (f.i. a raise in ramping rate limitations and preventive curtailments) and balancing costs remain uncertain.

The proposal to introduce an OBZ results from the structural congestion that - by Elia design - is integrated in the grid connection capacity of the PEZ to shore.

BOP understands and acknowledges the role of hybrid interconnector projects in the further development of offshore wind capacity in the North Sea. Extending the North Sea grid with few, short extra cables can enable to also use the cables that connect offshore wind farms with the mainland as interconnectors between countries, other wind farms. These hybrid Interconnections lead to an optimized use of limited grid capacity, as when there is no wind, power from further away can be transported in the same cable.

This approach is true for wind farms far away in the North Sea, located in between two countries. Adding an extra, relatively short cable in between such offshore wind farms, each connected with the mainland of only one country, can transform the cables into a hybrid interconnection, also connecting the two countries. Using a long term, planned approach for hybrid interconnections and as stated by ACER, can generate societal value.

However, the PEZ is not to be compared with far away offshore wind farms. The distance to the mainland is only a mere 40 kilometers, compared to the much longer Nautilus connection. Introducing a (grid) constraint in this last section of the cable shifts potential cable underutilization from a short section of cable to a long section of cable. This cannot be the most beneficial for society. Belgium is ‘short on renewables’: an extra interconnection with the UK (Nautilus) should enable Belgium to import more renewable power from the UK, also when the PEZ is producing power at full load.

Due to timing constraints and delays in proceeding with new grid capacity projects, the grid developments lack behind and a synchronization problem occurs between faster offshore wind developments and slower grid extension. In this context shortage in grid capacity can be temporary. **In order to avoid slowing down offshore wind developments while waiting for a new regulatory framework developments, a fast and steady regulatory solution is required in the benefit of society and the climate in general.**

Additionally, it is expected that in reality the grid connection capacity to shore will exceed the 3.5 GW quoted by Elia, due to on the one hand increased HVDC link capacity (2 GW is the industry standard instead of the referenced 1.4 GW) and by utilising the dynamic rating of the AC system due to the inherent volatility of the load. This however may result in congestion to occur on the onshore grid due to insufficient grid capacity in the West of Belgium, but this structural onshore congestion should not be the reason to artificially reduce the grid capacity from the energy island and to create an offshore bidding zone.

Figure 70 refers to a technical capacity of the DC link of 1400 MW. Has Elia considered a 2 GW connection, which is industry standard for a 525 kV bipole and therefore more readily available? This would have the additional benefit of reducing the congestion on the energy island connection to shore.

Several conditions with large uncertainty and varying time horizons (if realized at all) are presented as key enablers to introduce an OBZ. These span technical risk to the grid stability and security of supply (single node operation, DC circuit breakers,...), regulatory evolutions (implicit market coupling with the UK,...) and project risks (go-live of Nautilus and TritonLink).

Considering the uncertainty related to each of these conditions, the only sensible path forward is to proceed with a Home Market Design until all of the preconditions are satisfied (and not just 1 precondition as proposed by Elia, being the return of the UK to the implicit market coupling), after which a thorough analysis of the impact and mitigating measures to implement an OBZ can be performed.

4.2. Advanced Hybrid Coupling (§4.3.2)

Advanced Hybrid Coupling (AHC) is referenced as a needed building block to realise the OBZ target market design in order to avoid reliance on forecast to calculate exchanges on external borders. While the public consultation references a 2025 timeframe for the switch from SHC to AHC, the NRAs have requested an extension of the timeline to decide on the TSOs proposal related to AHC. Concerns have also been expressed by industry that the theoretical improvements that may follow from AHC may not be feasible due to performance limits within Euphemia. Furthermore, AHC is expected to an increase in lower energy prices for OWFs and an increased volatility compared to SHC. These factors combined lead to further uncertainty with respect to the market design proposed by Elia.

4.3. Target market topology (§4.3.3)

Reference is made to a Belgian and a Danish offshore bidding zone. Is it correctly understood that the target market design is to have a nodal OBZ for each "energy hub" of the meshed offshore hybrid grid, i.e. no zonal OBZ across several energy hubs is envisaged?

Does Elia have a timing in mind to couple other offshore bidding zones to the OBZ_BE?

Can Elia deliver insights in the amount (in hours per year or season) of (partial) congestion and network constraints? Please provide insights in 1) local congestion towards the Belgian shore and 2) congestion from the Belgian shore to the Belgian load centres. How frequently will the OBZ price deviate from the Belgian price, in the next 40 years?

If Elia cannot easily answer these questions, one cannot assume that private parties (the OWFs, but also the corporate (or cooperative) offtakers) can.

4.4. Role of 2-sided capability based CfD

Reference is made throughout the Market design chapter to the two-side capacity based CfD mechanism as a fundamental piece of the puzzle to derisk investments in the PEZ OWFs. The tender conditions however allow for a carve out up to 75% of the volume (50% corporate PPA, 25% cooperative PPA) and the CfD price stabilisation mechanism only applies for a period of 20 years of the total ~ 35 years of operational life. The price and volume risks that result from the OBZ and AHC, and the transfer of welfare from OWFs (price reduction and increased volatility) to Elia (increased congestion rent) resulting from the introduction of an OBZ therefore are not adequately accounted for.

4.5. Use of Nautilus (§4.5.1)

Does Elia have an insight or expectation on the foreseen usage of the nautilus connection?
Is there a high RES infeed expected from the UK? What is the correlation between wind production in South of the UK and North of Belgium?

5. Balancing design

5.1. Respecting the current market design and roles

The BRPs should be sufficiently incentivized to balance its portfolio, but it must remain the BRP's prerogative to choose the appropriate means to fulfil its balancing obligation. The provided incentives should foremost be market-based, technology-neutral and applied at the level of the BRP's portfolio.

The proposed measures that are asset-based, technology-specific and applied at the connection point (or for some proposed at the turbine level), are to be applied as last resort measures only with clear criteria and activation triggers and are to be fully remunerated in accordance with the EU Electricity Market Regulation.

BOP is of the opinion that many of the proposed mitigating measures at least to some extent interfere with the distinction between BRPs and their responsibility, and the TSO and its responsibility. A BRP is responsible for balancing its portfolio, on a best effort basis, and Elia as TSO is responsible for grid security and stability. The BRP is incentivized to fulfil this obligation as he is exposed to the imbalance price while additional liabilities are foreseen in the regulatory framework. **The mitigation measures should not hamper the BRP to fulfil its obligations in any way.** Elia should at all times ensure a level playing field between BRP's without offshore wind production and BRP's with offshore production in their portfolio and Elia should observe the principle of non-retroactivity of the mitigating measures related to the existing offshore parks. The mitigation measures should therefore be coherent and not create any distortion between different actors and/or technologies.

The identified issue related to balancing, i.e. a fluctuating and intermittent electricity generation profile with the possibility of fast ramping events in both directions that requires a flexible energy system, is **not specific to offshore wind but rather a feature of several renewable energy sources**, and given the energy transition, an important aspect of the energy market of tomorrow. A system-wide view of managing these fluctuations has to be developed.

This would mean that, with respect to the measures implying constraints for wind parks, Elia can only activate a measure as last resort and based on objective criteria and activation triggers (which still need to be developed). All measures should be up for re-evaluation on a regular basis, e.g. every 2 years, to confirm the actual need of the measure and/or adjustment of the activation criteria. If the need is no longer confirmed, the measure is to be automatically deactivated. Such an approach allows for more flexibility in time to introduce new measures and avoids overregulation when the need is no longer there.

5.2. Remuneration is required according to the EU Electricity Regulation (2019/943 art. 13)

Art. 2(26) of the EU Electricity Market Regulation defines 'redispatching' as a measure, including curtailment, that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion or otherwise ensure system security;

'Redispatching' should therefore be understood as any ad hoc correction/reduction of the specified production of a given power-generating unit for reasons related to system security, including - but not limited to - the case of congestion. In other words, 'redispatching' within the meaning of the Electricity

Market Regulation is a more broadly applicable measure that is not limited to congestion management. This is confirmed as such in authoritative legal doctrine, see e.g. J. PAPSCH (Deputy Head of Unit at the European Commission (DG ENER)):

> *“Thus redispatching goes beyond the classical meaning of ordering one generation facility to ramp up and another to ramp down in order to relieve congestion and includes other instructions to generation facilities in the interest of maintaining system security such as limiting generation from synchronous generators.”*

This interpretation is also evident from the legislative process. In the original proposal of the European Commission with regard to the Electricity Market Regulation, the distinct concepts of 'redispatching' and 'curtailment' were always used side by side in Article 13 (Article 12 at the time). In the context of the trialogue negotiations, both concepts - initially side by side - were subsequently integrated into a single definition of 'redispatching' (cf. the formulation "including curtailment" and "or ensuring system security in some other way" in the definition of 'redispatching').

In accordance with art. 13 of the Electricity Market Regulation, the principle is that redispatching of units must take place using market-based mechanisms where financial compensation is provided (pay-as-bid or pay-as-cleared). Non-market-based redispatching should only be used when (i) no market-based alternative is available; (ii) all available market-based resources have already been used; (iii) the number of eligible units is too low to ensure effective competition in the area where eligible units to provide the service are located; and (iv) in case of a risk of strategic bidding (due to the very regular and predictable occurrence of congestion).

In case of non-market-based redispatching (i), renewable energy production units should only be subject to downward redispatching if no other alternatives exist or if other solutions would lead to significantly disproportionate costs or serious risks to the safety of the network ('priority access'); and (ii) financial compensation is due from the transmission system operator (to cover the loss of revenue).

The proposed measures that result in non-market based curtailments are to be fully remunerated, including for the volume and period outside the 2s-CfD contract.

5.3. 2-sided CfD is not a full cover solution (§5.1/§5.7.2.3/§5.7.3.3)

Similar as in the Market Design chapter, reference is made throughout the Balancing Design chapter to the two-sided capacity based CfD mechanism as the reason why financial compensation to the OWFs is not needed when implementing these measures. For the same reasons, BOP disagrees with this statement.

The tender conditions however allow for a carve out up to 75% of the volume (50% corporate PPA, 25% cooperative PPA) and the CfD price stabilisation mechanism only applies for a period of 20 years of the total ~ 35 years of operational life. The price and volume risks that result from the proposed mitigating measures are therefore not adequately accounted for.

5.4. Increasing balancing market performance (§5.6.5)

Increasing the balancing market performance or availability of FRR and increasing the reaction speed for the activation of available FRR are mentioned as possible alternative mitigation measures. Why are these not addressed / further investigated to result in robust system wide measures to account for the change towards a more intermittent generation pattern of not only offshore wind but also onshore renewables and the expected increase in flexibility within the system?

5.5. High wind speed capabilities (§5.7.1)

BOP requests to specify the required behaviour at the Connection Point, to leave the specific design and functionalities at the WTG level with the developer.

BOP observes that the market is fast implementing HWRT technologies, and that this technology is becoming a customary feature for most turbine manufacturers. However, there are important differences in the workings of such technology, depending on the manufacturer and WTG model.

BOP would like to point out that HWRT is a feature on WTG level, whereas interventions from the grid operator should be limited to criteria at the wind park level at the Connection Point within the meaning of Article 1, definition 28 of the Federal Grid Code, similarly to the current approach whereby the technical requirements are applicable at the Connection Point.

The positive features of HWRT can be achieved via several, behind the meter, options. For example, ramping down in anticipation of a wind farm's cut-out can also be managed by the power plant controller. A wind farm can also consist of a combination of WTGs with and without HWRT, which together would still achieve the required behaviour in high-wind situations at the connection points.

Furthermore, BOP wants to avoid that a requirement for a certain HWRT technology or particular specifications at turbine level, would drive the turbine-decision of developers, significantly limiting the developer's negotiation power and thus driving up costs. In addition, a turbine-level specification could also impede behind-the-meter innovations.

Elia confirmed in the consultation report of the MOGII System integration study (23 December 2020, page 21): *"Unless the change in the assumptions leads to different conclusions in the updated study, the minimum requirements proposed at the turbine level in the report will be translated into a minimum requirement at the connection point."*

5.6. Ramp rate limitations (§5.7.2)

BOP is not opposed to a ramping rate limitation as a technical possibility, triggered by a system-wide indicator. However, BOP requests that it is remunerated in accordance with the EU Electricity Market Regulation and that it should be applied in a technology-neutral manner (i.e. not only offshore wind), as offshore wind is NOT (always) causing the balancing risk.

Design of the measure

With respect to the proposed design of the mitigation measure, BOP is in favour of Elia's attempt to limit the use of the measure to extraordinary situations, defined by a clear indicator or trigger.

However, as the System Imbalance trigger is a market-wide indicator, to which all connected assets contribute, BOP wonders why the ramping rate limitation is only applied to the offshore wind sector. The proposed measure is not technology-neutral.

It is understood that the ramping up of OWFs in case of a large positive imbalance aggravates an already present risk, the actual market players responsible for that risk are in fact the market players responsible for the system imbalance in excess of 500 MW, and not necessarily the OWFs as alluded to by Elia.

Financial impact

The financial impact for the volume covered by and during the period of the 2s-CfD is limited to the balancing costs. But the 2s-CfD is limited to 20 years vs 35 years of operational lifetime and the volume under 2s-CfD might be limited to 25%.

We disagree that the financial impact is limited to the balancing costs for the part under a PPA, as under Pay-as-Produced PPAs, it is not the day-ahead volume forecasts that are sold, but the actual production (plus any curtailments on the request of the buyer). Only few offtakers will be capable of covering production limitations that are 'forced' on the OWF by external parties. Therefore, the loss of production potential can never be recovered, and will increase the required strike price.

Remuneration is required according to the EU Electricity Regulation (2019/943 art. 13)

Ramping rate limitations clearly are categorized as non-market based redispatching and as such are to be renumerated.

5.7. Cut-in coordination for existing wind farms

Cf. Exhibit "Existing cut-in coordination" (page 218)

In the alternative solution proposed by Elia as 'Automatic Cut-in coordination" the existing wind farms are allowed to come back online according to a predetermined linear ramping rate. The document mentions that each park will be able to come back online within a period of around 1 hour after the request to come back via the SA (whereas most parks are capable of coming back online in a time span of 5-10 minutes). Such a limitation is de facto a curtailment at request of the grid operator and is to be categorized as non-market based redispatching and as such is to be renumerated in accordance with the EU Electricity Market Regulation art 13.

Furthermore, BOP disapproves that this proposed ramping limitation in the context of a cut-in coordination would occur irrespective of whether it is required for system security, without any compensation to the relevant OPA or SA, and without the clarification that this can only be imposed in case of incorrect behaviour of the OPA/SA with regards to his obligations, as per the relevant T&Cs.

The default situation should be that the existing offshore wind farms can come back online as per their technical capability and that BRPs are responsible for managing these events in their portfolio. Only in order to safeguard the safety of the network, Elia is allowed to impose restrictions on asset-level and these measures are to be fully remunerated.

5.8. Preventive curtailment (§5.7.3)

BOP is not opposed to preventive curtailments as a technical possibility, triggered by a clear system indicator. However, BOP requests that such a measure is remunerated in accordance with the EU Electricity Market Regulation.

BOP is in general not in favour of preventive measures that are technology-specific and applied at the asset level; as such interventionist measures diffuse the roles of the TSO and the BRPs.

Offshore BRPs are incentivised to deal with storm events through the imbalance market and the current storm procedure. At the moment, they have several means to deal with imbalances due to storm events, such as HWRT, intra-day balancing or even curtailments at their own decision. However, they may not be sufficient at times. Therefore, BOP supports the initiatives by Elia aimed at further increasing the balancing options available to BRPs, such as demand-side response, increased intra-day liquidity, etc.

Financial impact

The financial impact for the volume covered by and during the period of the 2s-CfD is limited to the balancing costs. But the 2s-CfD is limited to 20 years vs 35 years of operational lifetime and the volume under 2s-CfD might only be 25%.

In addition, BOP would like to point out that **curtailment has an impact on the lifetime span of the design of foundations** (and potentially the WTG tower and the mechanical drive train, blades and bearings) especially when not damping due to operation, i.e. during high the wind situations in which preventive curtailments would occur. A wind turbine is designed to have its rotor in rotation for all windspeeds according with the power curve. Same for the turbine tower and foundation. The rotor in rotation is serving as a consistent oscillation. When the turbine is standing still, the forces of wind and waves are not damped by this consistent oscillation resulting in a much higher impact and fatigue. The lifetime consumption of a preventive curtailment (which is by definition during quite high winds) is thus many times higher than if the turbine can continue normal operation. During tower and foundation design, this will need to be taken into account, leading to a heavier and thus more costly design. Besides the link with the structural integrity of the foundation and turbines, there is also a link with the certification of the WTG. The industry goes towards 35y lifetime certification, which trades off against fatigue and start/stop events.

Remunerating preventive curtailment ensures correct balances and incentives for the grid operator when choosing between "reducing at the source" or "finding solutions in the reserves market". Determining a system for remuneration is not complicated, and many examples that Elia uses today, already exist, including the non-contracted energy bids and the remuneration for the MOG-unavailability.

Remuneration is required according to the EU Electricity Regulation (2019/943 art. 13)

Preventive curtailments clearly are categorized as non-market based redispatching and as such are to be renumerated.

Downward ramping events

Elia states the extension of the preventive curtailment measure to normal, non-storm, conditions is needed to mitigate the effect of downward ramping events "provided that a reliable forecast of such events can be developed".

Considering the difficulty of adequately forecasting downward ramping events and the performance of Elia's existing forecasting tools, extending preventive curtailment to non-storm conditions is not considered an acceptable measure in its current form.

5.9. Real-time operational preventive cap (§5.8.2.1)

The preventive cap is introduced to prevent "overloading of the HVDC system". Cf. 5.8.2.1 page 232 "*The preventive cap is implemented as a real-time injection limit enforced by Elia on the wind parks to safeguard operational security in the HVDC system.".* This clearly categorizes the real-time operational preventive cap as a non-market based redispatching and as such is to be remunerated in accordance with EU Electricity Market Regulation.

BOP questions the need for a real-time operational preventive cap applicable to the offshore wind parks connected to the HVDC system as onshore grid constraints will be the bottleneck in the system. In accordance with the EU Electricity Market Regulation this proposed measure is to be categorized as non-market based redispatching and as such are to be fully renumerated.

Due to uncertainty of the single node vs two-node operation, the wind parks in the first two concessions also are subject to an additional uncertainty whether this preventive cap will applicable. A perspective on the hours of activation and loss of production is to be given in the tender requirements documentation to be able to account for this uncertainty. Obviously, any additional uncertainty drives up the strike price.

Can Elia further clarify which part of the HVDC system is expected to be the bottleneck in their current design? Note that the time constants which may be acceptable in terms of overloading are completely different for HVDC converters and HVDC cables.

Furthermore and as mentioned in relation to the structural congestion between the energy island and the Belgian onshore grid, 2 GW is the industry standard for bipole 525 kV HVDC converter stations instead of the 1.4 GW referenced throughout the public consultation. There is therefore ample opportunity to avoid, or at the very least reduce, the need for this preventive cap and to possibly rely on the existing measures for congestion management.