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Task Force MOG 2

10th of January 2023

Agenda

Task Force MOG 2 [13:00 – 16:00]

- **Presentation by the Cabinet**
- **Stakeholders interactions**
  - *General overview results call for feedback and process*
  - *Feedback on exchanges around forced oscillations*
- **Introduction on technical challenges for AC & DC coupling MOG 2**
- **Balancing - MOG 2 system integration study**
  - *Impact of MOG 2 on reserve dimensioning*
  - *Impact of MOG 2 on mitigation measures for storms and ramps*

Workshop MOG 2 [16:00 – 17:00]

- **Market design MOG 2 and OBZ process**

Stakeholder interactions

- *General overview results call for feedback and process*
- *Feedback on exchanges around forced oscillations*

General overview results call for feedback and process

| Elia Group

Overview main messages for feedback received from stakeholders

Grid design	▪ Clarification asked on **operation of energy island (SLD) 1 node vs 2 nodes**. ▪ Question **challenging the final grid design** proposed by Elia for MOG 2 and grid design ✓ **Bilateral meeting** was organized this with BOP/Otary regarding grid design question. The **support of this exchange is available on Elia TF website** ✓ **Operation of energy island 1 node** (AC and DC coupled) and **2 nodes** (AC and DC decoupled) will be introduced **today in this TF MOG 2 (see next slides)**	**Today**
Market design & OBZ process	▪ **Implicit vs explicit and HM vs OBZ, uncertainties impact UK Brexit, 1 node vs 2 nodes** ▪ **Legal process of OBZ** and integration of OBZ configuration in **tendering OWF MOG 2** ▪ **Questions on long-term perspective** ✓ Those questions will be addressed in the **workshop MOG 2 planned today (see next slides)** ✓ **Additional information** are provided in **Appendix**	**Today**
Balancing design	▪ **Concerns on high balancing costs** without access to balancing resources in UK (request in-depth analysis) ▪ How **to deal with absence of portfolio** netting options for **BRPs** ▪ **Impact** of **an OBZ on mitigation measures** ▪ Quid **BRP balancing obligation/option** ▪ Request on analysis / projections on **imbalance prices in UK / BE** ▪ Position that **without real balancing options** an imbalance price does **not** provide **useful incentives for BRPs** ✓ Elements relevant for reserve dimensioning and mitigation measures will be presented in the TF MOG 2 of today ✓ The other aspects related to balancing and Impact OBZ not covered in this presented will be addressed - to the extent possible – during the next TF MOG 2	**Next workshop**
CfD	▪ Link and combine **TAG (Transmission Access Guaranteed) with CfD principle** approach and cost transfer between OWF & TSO ▪ Proposal of **CfD strike price = offshore BZ price** ✓ **Elia aims at making the link with the support scheme when more details are known**	**Next workshop or later**

Feedback on exchanges forced oscillations

Update stakeholders interaction for forced oscillations

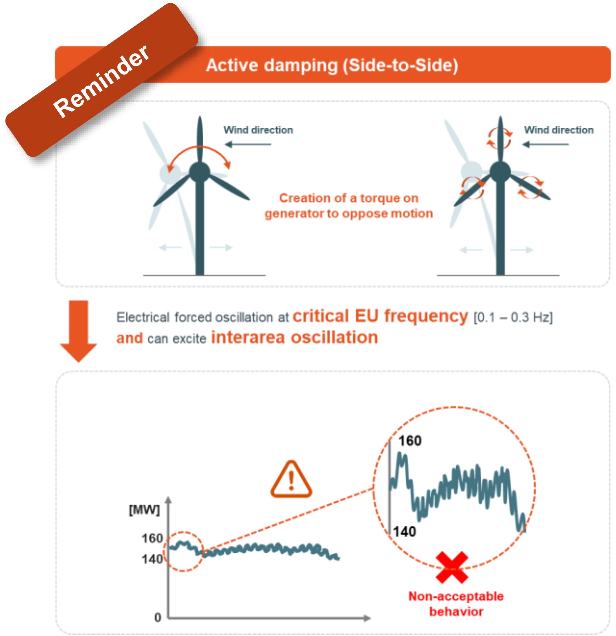
Fortunato Villella

Update stakeholder interactions for forced oscillations

Context

- **During the TF MOG 2 (24/06), Elia presented the main potential clarifications foreseen in the technical requirement** for 1st tendering of MOG 2 OWF
- In this framework, the **forced oscillations and interearea phenomena** and their critical consequences for EU system **were introduced by Elia**

➡ “ *This **phenomenon is to be avoided** by proper design of wind farms (problem to be solved at the source) and where **no onshore solution exists today*** ”



Requests

- **BOP** and **CREG requested to investigate onshore options** and perform a **CBA between offshore and onshore options**

➡ **Proposal to use the European Transition Funds (ETF) framework for this initiative**

2 parallel tracks ongoing for requirements of forced oscillations phenomena

BE track : ETF application for a research project – Starting Sep. 2023

- **Studying and describing the cause of the phenomena**
- Identifying and researching **potential mitigation measures (onshore and offshore)**
- Mitigations measures will be **assessed first based on their technical feasibility** from a societal cost perspective
- The **development of potential mitigation measures** will depend on the success of the previous phases regarding the understanding of the phenomenon.

- **Universities:** UCL, KUL
- **Laboratory:** Engie Laborelec and Engie Impact for PM
- **Advisory board:** Elia Group, Belgian offshore players and manufacturers (Belgian Offshore Plateform, GE renewable Energy, Ocean winds, Otary, Parkwind, Siemens Energy, Vestas, Hitachi Energy).

EU track: ENTSO-E proposal for network code update to ACER

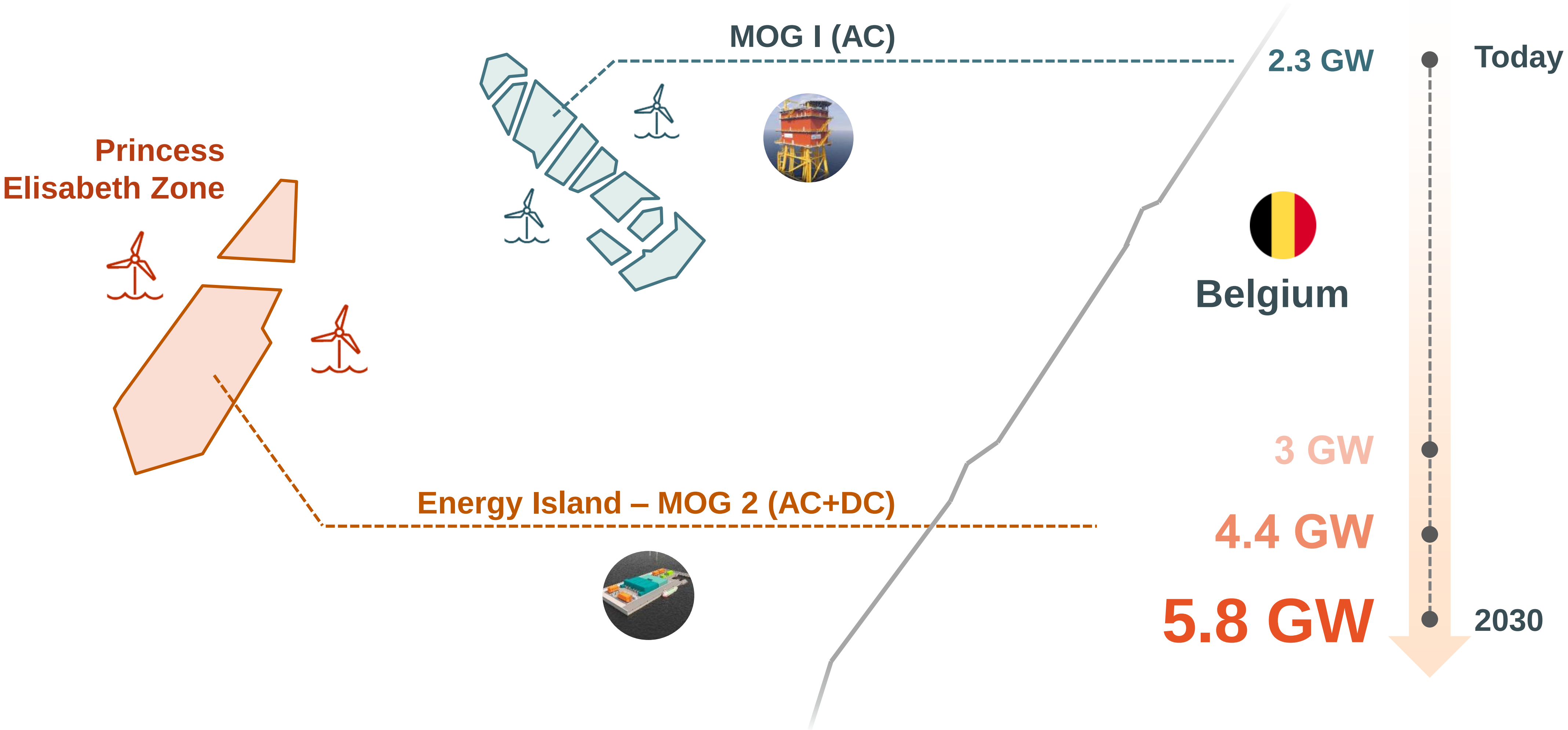
- **Different formulations for update of network code to limit forced oscillation** have been proposed to ACER based by ENTSO-E, WindEurope and wind turbine manufacturers
- **WindEurope and ENTSO-E aiming at a joint proposal towards ACER by Q1-Q2 2023**
- **Vendors** will **look at a solution** to limit the forced oscillations based on **a control system development** with no impact on the hardware (steel) to be used and only consists on a software development: **very limited impact on the cost** (only software development & testing) but may **require time for implementation**

Introduction to technical challenges of MOG 2 AC and DC coupling

Bertrand Vosse
Olivier Bronckart

1. Currently planned grid design

MOG 2 will integrate up to **+3.5 GW** offshore capacity through the Energy Island to the Belgian coastal area by **2030** with **AC and DC** connections

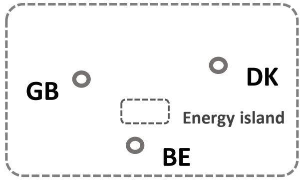


MOG 2 is one step in the offshore grid development of the Belgian Coastal area

2025 2026 2027 2028 2029 2030 2031 … 2035 … 2040

Energy Island

*The energy island is foreseen to be built by **2026** and w**ill trigger the construction** of the first phase of **MOG 2 (700 MW AC)***

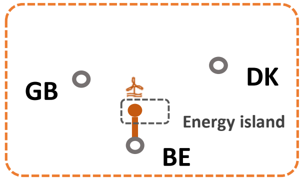


MOG 2

700 MW (AC) – phase I

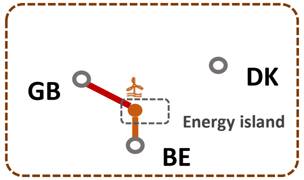
2100 MW (AC) – phase II

3500 MW (AC & DC) – phase III



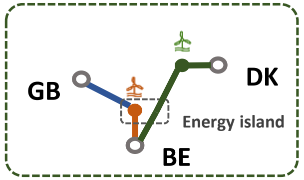
Nautilus

Nautilus hybrid interconnector (BE-GB) will be connected to 1.4 GW OWF connected in DC (phase III MOG 2) by 2030



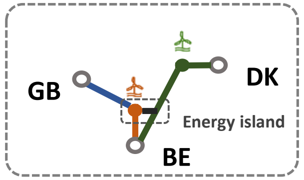
TritonLink

TritonLink hybrid interconnector (BE-DK) will connect 2 GW OWF in DK by 2031

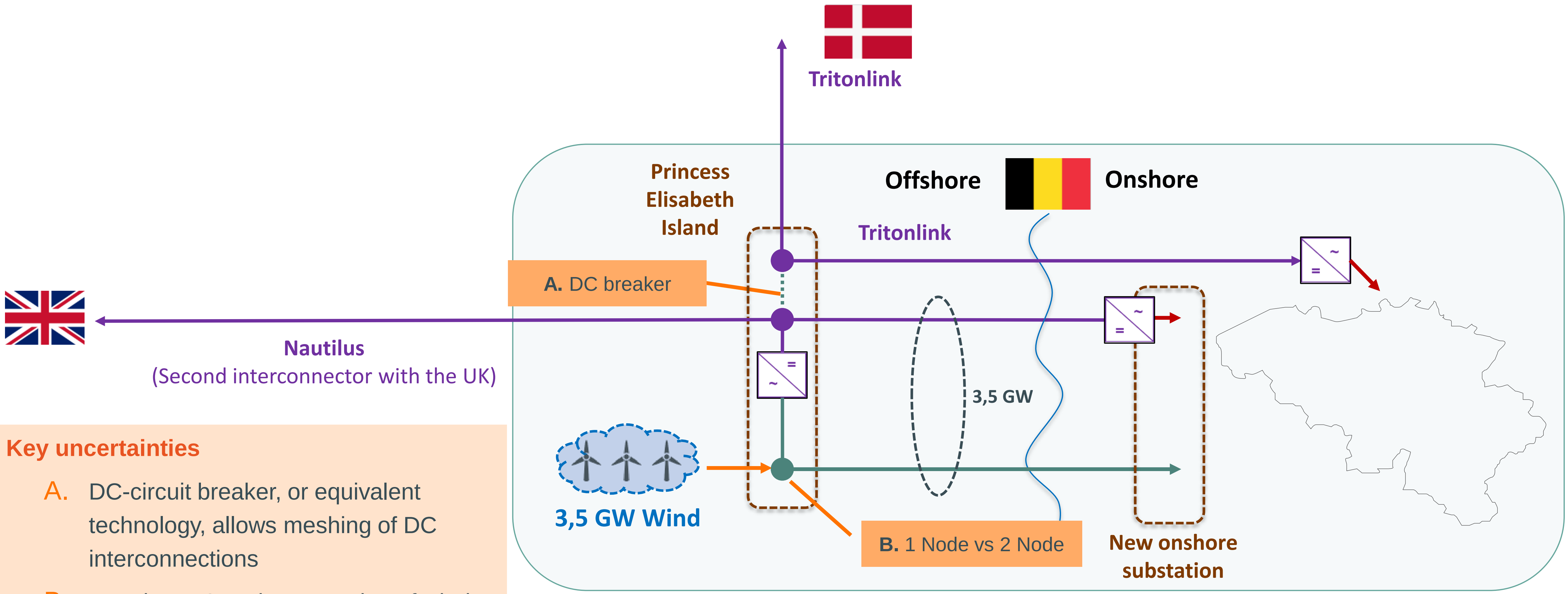


Energy hub

HVDC substation on energy island to create an energy hub (BE-UK-DK)



Currently planned grid design



Key uncertainties

A. DC-circuit breaker, or equivalent technology, allows meshing of DC interconnections

B. 1-node vs. 2-nodes operation of wind.

Note: figure shown is the anticipated configuration in the FDP 24-34 for the Interconnectors Nautilus and Triton.

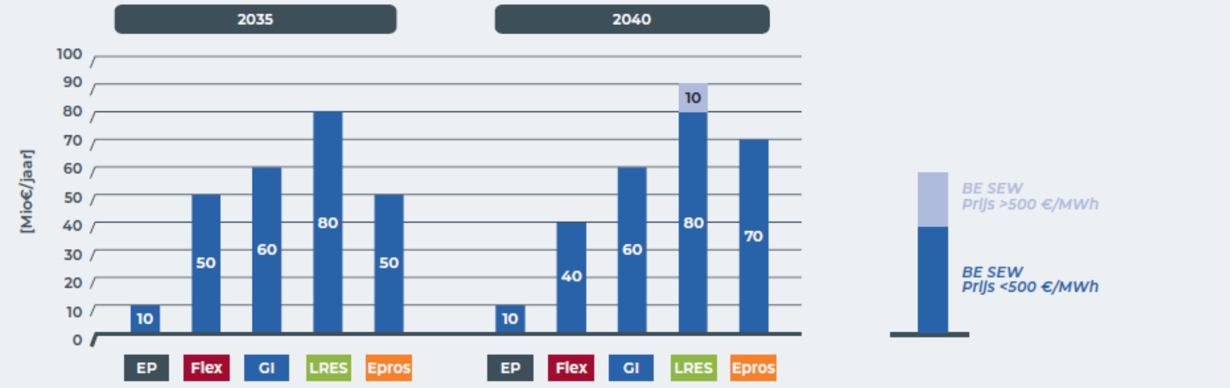
Currently planned grid design – Rationale behind…

The DC Circuit Breaker

- It allows a more optimal use of the infrastructure of MOG2, Nautilus & TritonLink by exploiting the decorrelation between the various flows.
- It allows direct flows between MOG2/Nautilus and Denmark while avoiding the Belgian onshore grid.
- It offers MOG2/Nautilus an additional exit door to the Belgian onshore grid.
- This effectively translates into Socio-Economic Welfare increase for the Belgian and EU society (reduced spilled energy, increased price convergence,…).

This project is in the draft Federal Development Plan 2024-2034. Announced in **2035-2040** with a status **“conditional”** given the **technological uncertainty**.

FIGUUR 4.14: BELGISCHE WELVAART GEGENEREERD DOOR HET PROJECT OFFSHORE ENERGY HUB

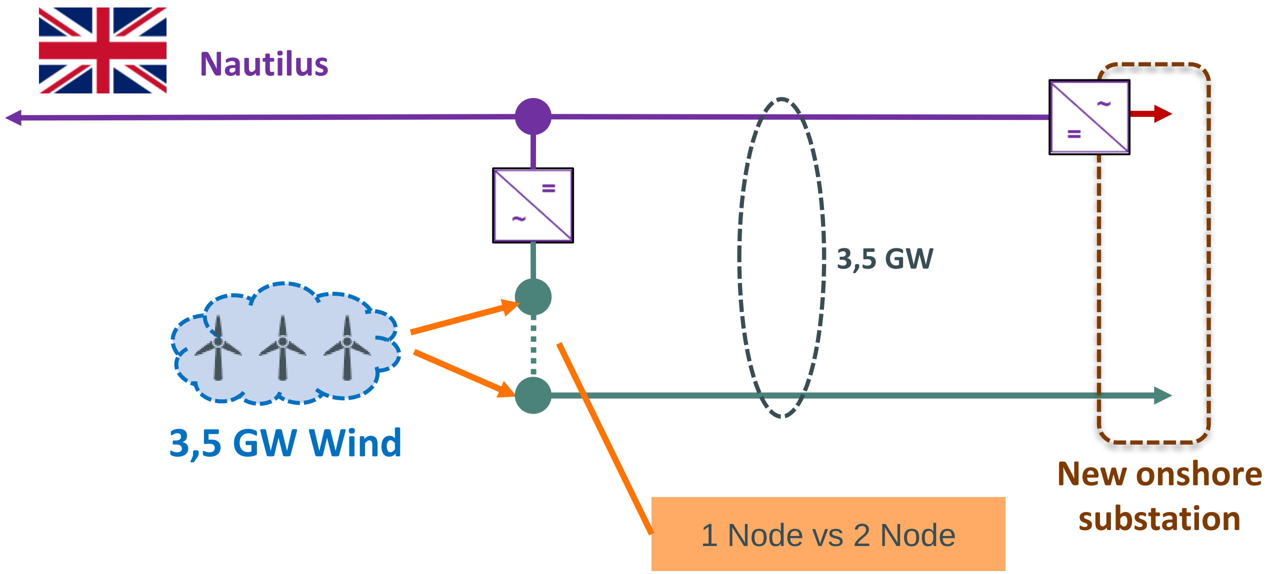


FIGUUR 4.15: EUROPESE WELVAART GEGENEREERD DOOR HET PROJECT OFFSHORE ENERGY HUB

Currently planned grid design – Rationale behind…

The 1-node operation

- It increases the redundancy of the Princess Elisabeth island by allowing power transfers from the AC side to the DC side and vice-versa in case of loss of a cable (AC or DC) or a DC pole or even the whole DC system.
- It allows a hybrid use of the AC cables.
  - The extent of this hybrid use will however be limited by the technical specifications of the AC cables.



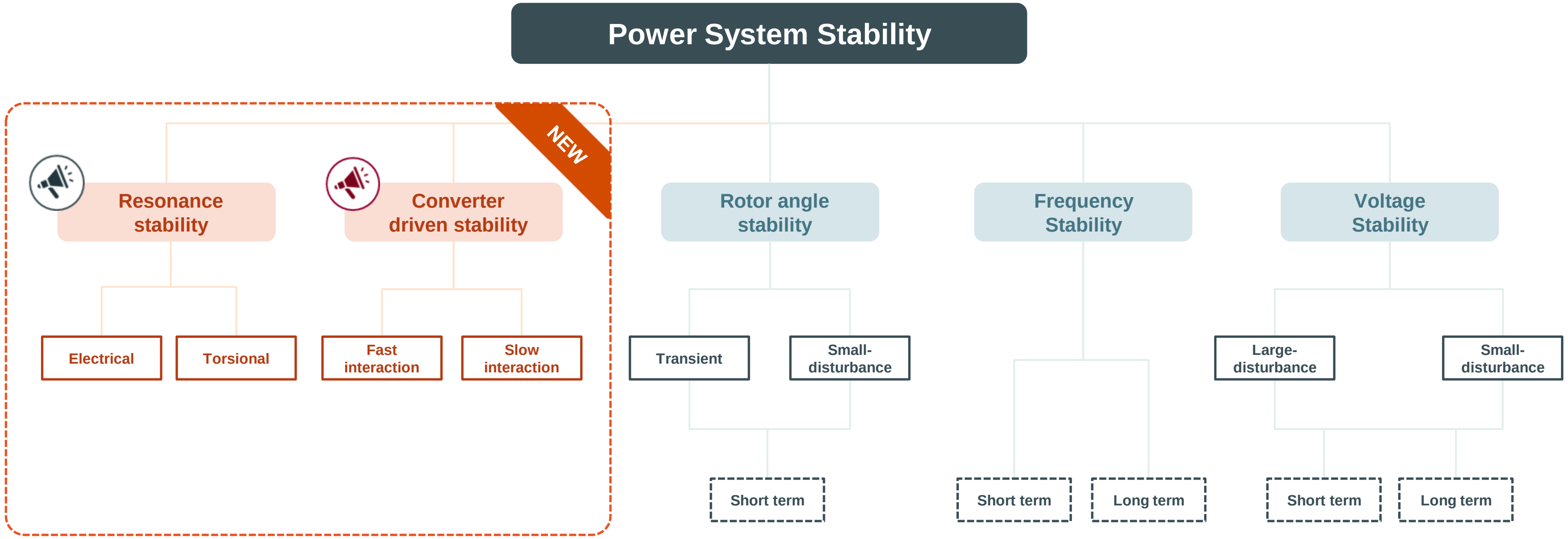
2. Technical challenges

In parallel to those ambitions, the system will face massive changes in the coming years that will lead to new power system stability phenomena and a reduced system strength

Reminder

Recent and new trends

- Increasing & accelerating RES ambition
- Development of offshore grid
- Increase of power electronic converter & interface devices
- Partial nuclear phase-out
- Increasing exchanges over long distances



NEWS

Several consequences of these new phenomena due to interactions with power electronics were observed abroad

Event - Asset damage in Germany

- Offshore HVDC damages due to harmonic interaction
- Solved by adding filters
- HVDC out of service for some time

  → **large non-injected power**

  → **additional cost for system**

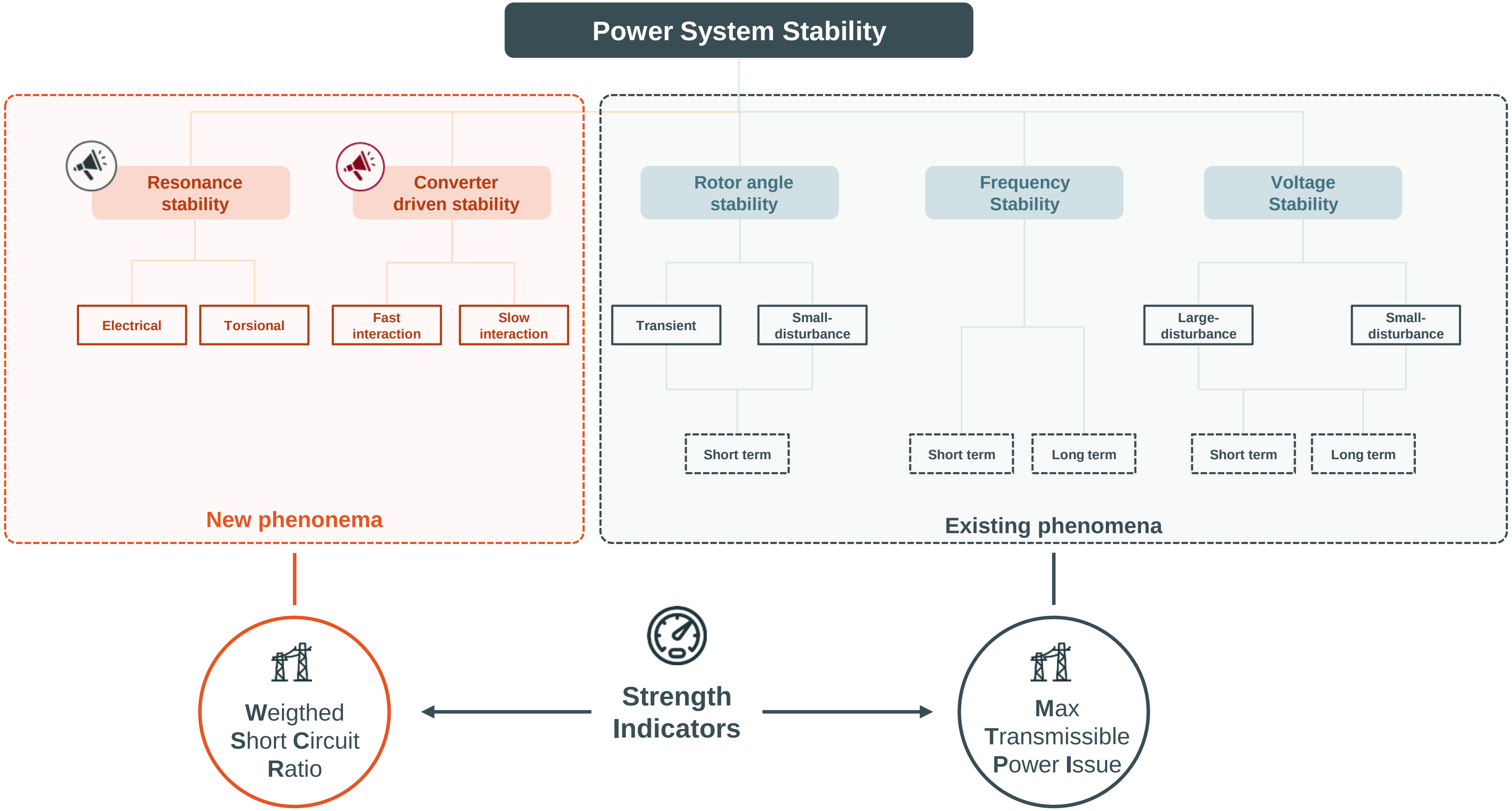
Event - System security issue

- Disconnection of injectors and cascading
- Local/global black-out
- Reputation/regulatory

  → **additional important cost for system**

(Example unavailability of the MOG (1GW) has a cost 0,5M€ -1,5M€/day)

Two main criteria are used to assess the system strength against existing and new phenomena



$$\text{Weigthed Short Circuit Ratio} = \frac{\text{Short circuit power coming from AC grid} * \underline{\text{Installed}} \text{ power of power electronics}}{(\underline{\text{Installed}} \text{ power of power electronics})^2}$$

$$\text{Max Transmissible Power Issue} = \frac{\text{Short circuit power coming from AC grid*}}{\underline{\text{Injected}} \text{ power}}$$

Note : Short-circuit power from AC grid = picture of electricial distance of different generating sources installed in the grid)

Grid strength for new phenomena (resonance stability and converter driven stability) is usually assessed with the weighted short-circuit ratio

- $S_{SCL,i}$ = *Short-Circuit Level at bus i before the connection of IBR i [MVA]*
- $P_{rated,i}$ = *Power rating of the IBR i [MW]*
- *N = Number of IBR interacting with each other*
- *i = IBR index.*
- *IBR = Inverter based resource*

Weigthed Short Circuit Ratio

$$= \frac{\sum_{i=1}^{N} S_{SCL,i} * P_{rated,i}}{\left(\sum_{i=1}^{N} P_{rated,i}\right)^2} = \frac{\text{Short circuit power coming from AC grid * Installed power of power electronics}}{(\text{Installed power of power electronics})^2}$$

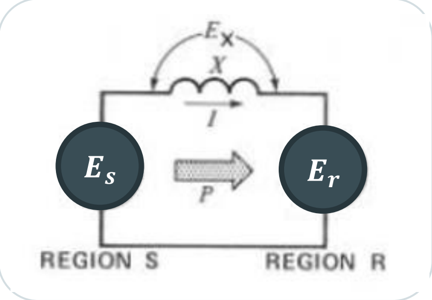
WSCR	Assessment	
> 2.5	**Acceptable**	▶ **Standalone tuning** of IBR control system is **often sufficient** to achieve satisfactory outcomes ▶ **Standard control system parameters** are **likely to work**
1.5 – 2.5	**Not guarantee**	▶ **Standalone tuning** of IBR control system is **not sufficient** due to increased risk of interactions with other nearby IBR ▶ **Site-specific control system tuning** is **likely to be required**
< 1.5	**Unacceptable** *(not working)*	▶ **Site-specific control system** tuning by itself **is not sufficient**. ▶ **Additional equipment** like **synchronous condensers** and **grid-forming inverters** will be required to achieve acceptable behavior

▶ When several IBRs are connected in close proximity to each other, they mutually affect the grid strength seen by each device

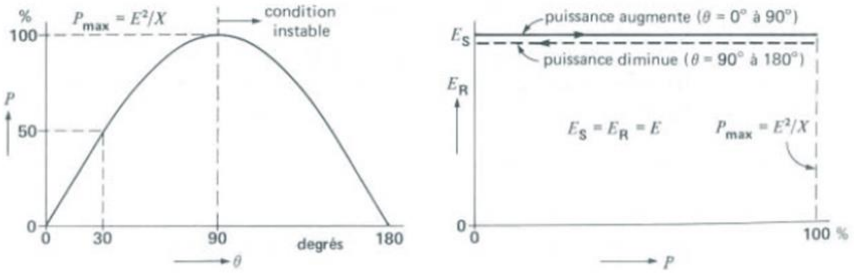
▶ The WSCR considers the system strength of a fictitious coupling point where all the nearby inverter-based generators are assumed to be connected

** IBR represents all resources asynchronously connected to the electric grid and are either completely or partially through power electronics (wind, solar, HVDC, energy storage etc)*

Maximum transmissible Power indicator



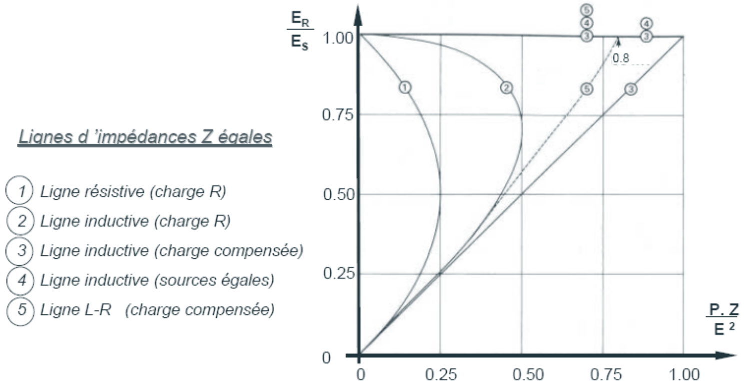
Angular stability limit



$$P = \frac{E^2}{X}\sin\theta$$

$$P_{max} = \frac{E_s * E_r}{X}$$

Voltage stability limit



$$P_{max} = \left[\frac{E_s * E_r}{2 * X} ; \frac{E_s * E_r}{X}\right]$$

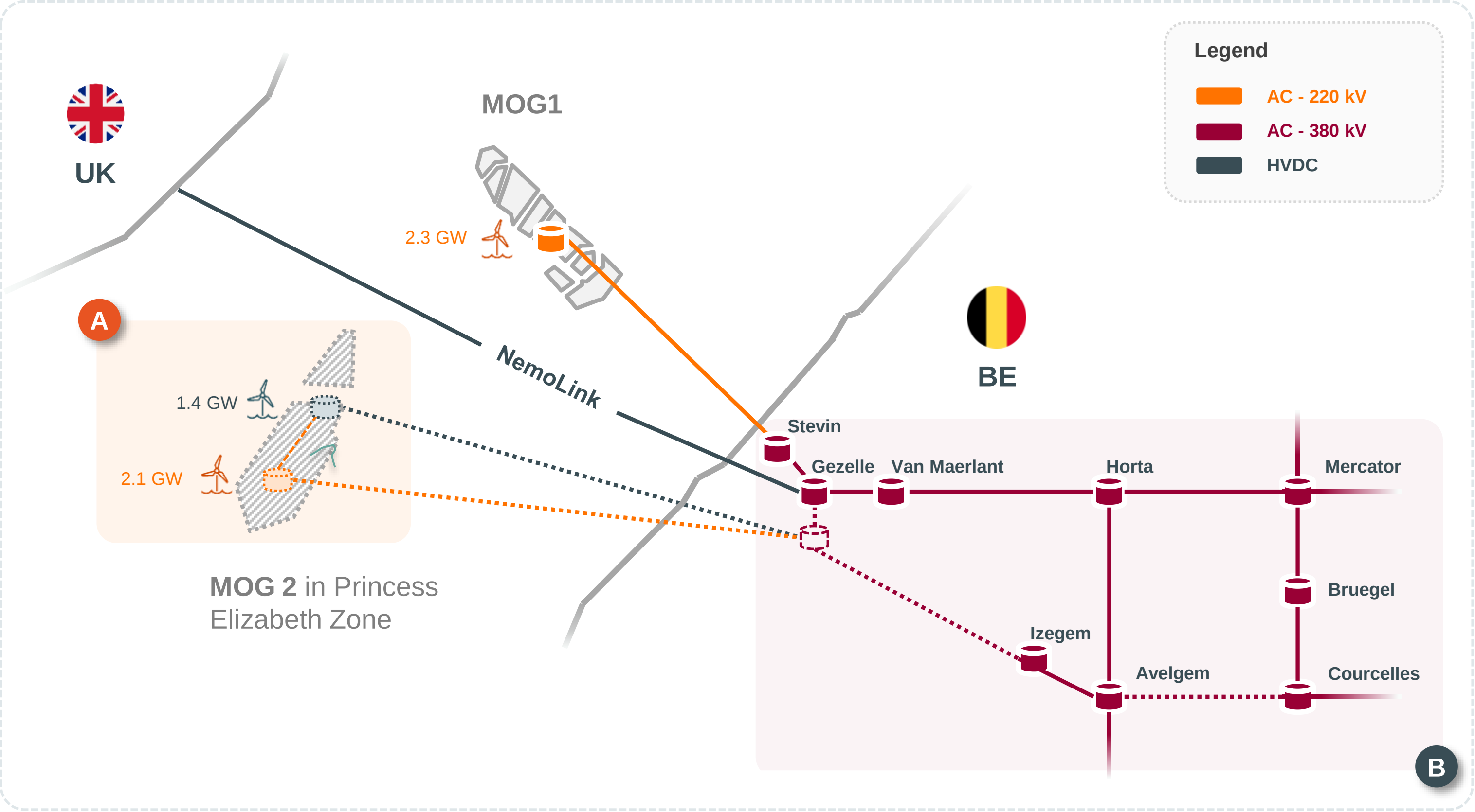
Note : 1/X ~= Scc = short-circuit power from the AC grid

! This is a stability limit, not a thermal (over)loading capacity !

Maximum transmissible power that can be injected in an AC grid is in all case lower than Scc and will vary between Scc/2 and Scc depending on the capability of the system to keep voltage constant from the wource to the sink

Such level of power electronics connected in antenna (and on top in weak grid connection) with MOG 2 is a worldwide premiere

MOG 2 grid design



WSCR from Energy Island and Onshore

	1 node	2 nodes
A Offshore	1.32	3.07
B Onshore	0.95	2.14

+3 syncons onshore

	1 node	2 nodes
A Offshore	1.51	3.53
B Onshore	1.05	2.33

* Values are indicative and are considering grid fully available (no contingency)

High concentration of power electronics in the coastal area, where grid condition in N are weak*, and even weaker in case of corridor trip for the stability and risk of interaction between the controllers

Overview of dynamic & harmonic challenges and risks for 2 nodes and 1 node operation mode for MOG 2

Challenges for 1 node

Challenges for 2 nodes

Challenge I: High concentration PEs

High concentration of PEs connected in one single weak point *CE synchronous area and leads to new power system stability phenomena that require onshore solution to mitigate them (synchronous condensers)*

Challenge II: Forced oscillation

Forced active power oscillations *observed on MOG I and to be anticipated on MOG 2*

Challenge III: Max Transmissible Power Issue N-2

Maximum transmissible power stability issue in N-2 *will require onshore grid solution (synchronous condensers, SPS)*

Challenge IV: Large concentration of multi-vendors

Larger multi-vendor *and will require process clarification for data and model process coordination*

Challenge V: Offshore voltage source needs

Significant increase of the level of PEs *driven converters on the offshore substation <=> require additional offshore voltage source (HVDC Grid forming control ?)*

Challenge VI: OWF operation mode AC, DC or both

Unclear if/how far it's technically possible for an offshore wind farm to work properly in ***different operation modes*** *(AC, DC or combined AC+DC).*

Challenge VII: short closed loop HVDC

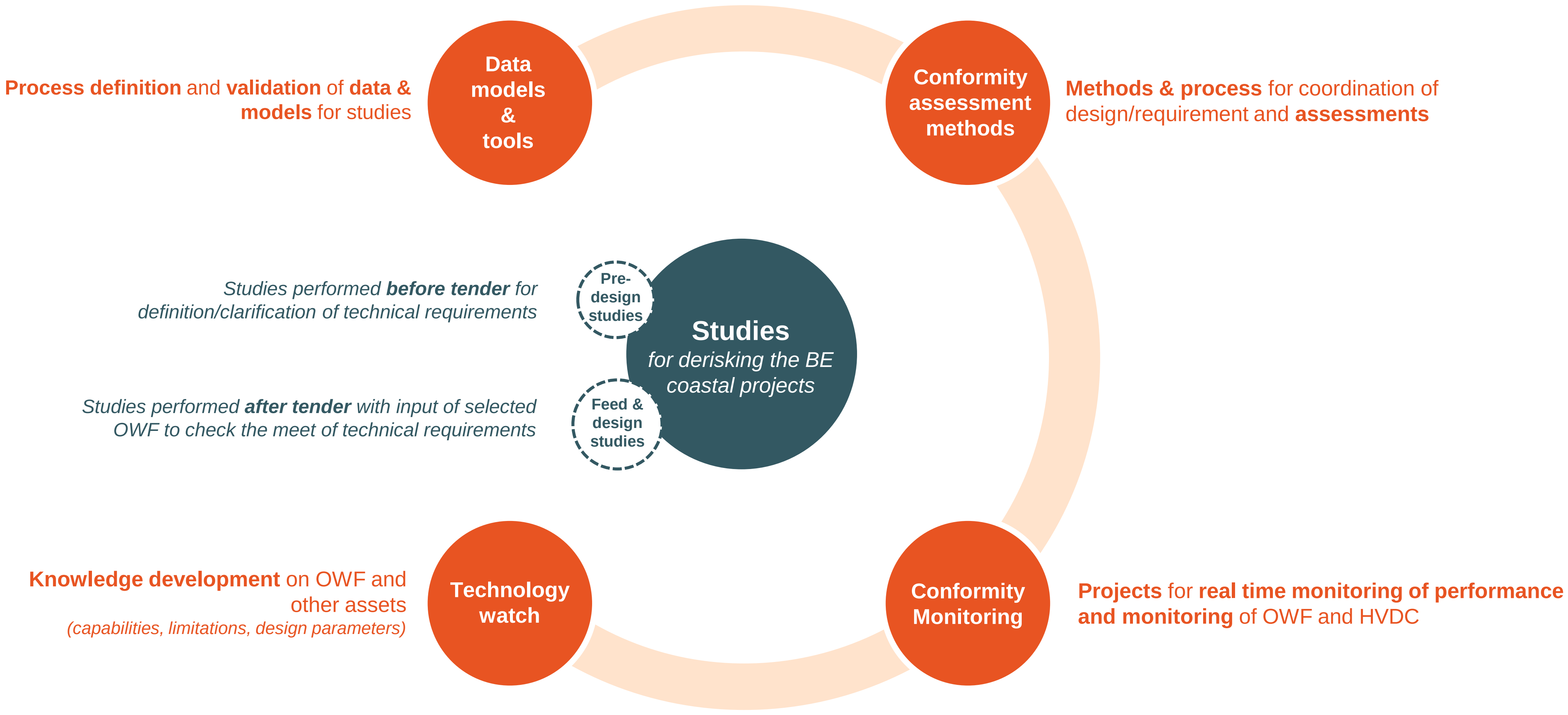
Embedded HVDC link with very short electrical distance between extremities *(very short closed loop between energy island and onshore substation)*

Challenge VIII: new protection scheme

Possibly new protection schemes to be designed: *new control command to ensure that defaults will be correctly eliminated in 1 node (and both operation)*

● = **Risks/challenges never met in Belgium/worldwide** and are unknown exploration area in terms of knowledge/expertise

Several activities and studies are required for derisking the Belgium coastal projects from pre-design till real time operation



Strategy is to secure the 2 nodes and striving for 1 node

Reference

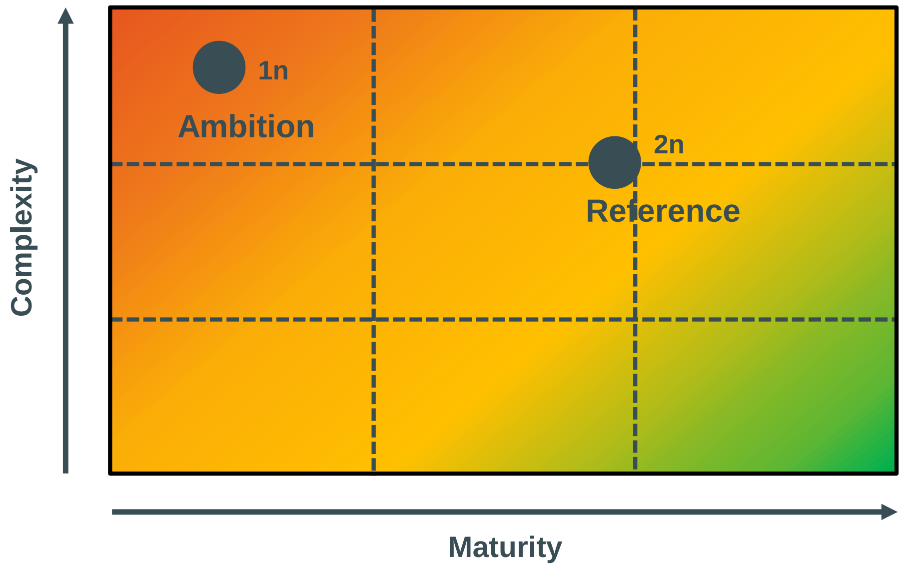
2n

2 nodes operation: ensure that the 3.5 GW of offshore wind capacity can be timely and robustly connected to the grid in 2 nodes operations

Ambition

1n

1 node: due to the high potential benefits for the society, the ambition remains to realize the AC and DC coupling (1 node)



The 1 node feasibility will be only ensured after the design phase of the HVDC with performance assessment (planned after the HVDC tendering) and test in laboratory, eg. around 2025-2026

Balancing

- *Introduction*
- *Impact of MOG 2 on reserve dimensioning*
- *Impact of MOG 2 on mitigation measures for storms and ramps*

Introduction

Kristof De Vos

Context of the MOG 2 system integration study

Elia | Elia Group

In 2019 - Elia initiated its MOG 2 system integration study which formulated recommendations for the system integration of offshore wind capacity up to 4.4 GW.

- These **recommendations included operational and technical constraints** for the wind parks or concerned BRPs which need to be specified before the **MOG 2 tender**.
  - ***June 2020*** *- Public consultation on assumptions, methodology and preliminary list of measures*
  - ***October 2020 -*** *Public consultation on the mitigation measures*
  - ***December 2020 -*** *Final report*

Public consultation page (link)

In 2021 - Elia initiated an update of the study on request of the stakeholders

- The objective was to confirm proposed **mitigation measures which imply technical and operational constraints for wind parks and/or BRPs** and parameters towards the **MOG 2 tender**.
  - *The scope, objectives and planning were validated with stakeholders on 28.06.2021.*
  - *The* ***update was put on hold*** *following new offshore developments communicated by the Minister*

Recommendations resulting from system integration study 4.4 GW

- Set of mitigation measures which imply technical and operational constraints for wind parks and/or BRPs
  - High Wind Speeds technologies
  - Ramping rate limitations
  - Preventive curtailment
  - Improve ability of BRPs to cover imbalances
- Set of general actions that need to be investigated by Elia
  - Incentivize reaction to real-time prices
  - Enhanced mFRR activation strategies
  - Enhanced forecast functionalities
- Existing mechanism with need to be monitored in the coming years
  - Current storm procedure
  - Alpha-parameter
  - Coordination of cut-in phase

In 2022 - Elia re-launches the update of the study :

- **Impact of increasing offshore wind capacity from 4.4 GW to 5.8 GW** on real-time balancing, reserve needs and proposed mitigations measures
- **Investigate impact of the offshore grid topology** (e.g. dimensioning incident) and the **creation of an Offshore Bidding Zone** (e.g. Elia's LFC structure / imbalance price area)

Scope of the update of the MOG 2 system integration study

Focus on balancing aspects

Projections of offshore generation profiles

Scope

Update simulation of future offshore generation profiles and corresponding prediction errors

- *During normal conditions*
- *During extreme wind power conditions (storms and ramps)*

Objectives

I. *Increase installed capacity projections up to **5.8 GW***

II. *Update of the **technology assumptions***

Impact on Elia's reserve needs

Scope

Update on Elia's expectations on future reserve needs and balancing capacity procurements*

Objectives

I. ***Analyze the effect of 5.8 GW** offshore on the system's **reserve capacity needs***

II. ***Analyze pre-conditions** of the market to manage reserve needs and costs*

Impact on mitigation measures for storms and ramps

Scope

Update of real-time system simulations

Confirm or amend proposed mitigation measures impacting the MOG 2 OWF tender

- *High wind speed technologies*
- *Preventive curtailment*
- *Ramp rate limitations*

Objectives

I. ***Investigate how the expected impact on the system** impacted by increasing the capacity to 5.8 GW*

II. ***Investigate if the proposed mitigation measures still adequate** in a 5.8 GW offshore context*

LFC block configuration

Scope

Assess the impact of an offshore bidding zone configuration on reserves, system operation and proposed mitigation measures

Objectives

I. ***Analyze the impact on LFC block** structure and balancing market organization*

II. ***Analyze the impact on reserve dimensioning**, real-time system operations and **recommended mitigations measures***

Market integration

Remarks :

- *Less relevant for the MOG 2 OWF tender but large impact on real-time system operation and costs*
- *Impact on system flexibility needs is kept outside the scope as the 5.8 GW was covered by 'high RES' scenario in the last Adequacy and flexibility study 2022-32 and analyses will be updated in the upcoming Adequacy and Flexibility study 2024-34 (June 2023)*

Projections of offshore generation profiles

Projections of offshore generation profiles

Scope

Update simulation of future offshore generation profiles and corresponding prediction errors

- *During normal conditions*
- *During extreme wind power conditions (storms and ramps)*

Objectives

I. *Increase installed capacity projections up to **5.8 GW***

II. *Update of the **technology assumptions***

- **In the framework of the MOG 2 study (2020),** the Technical University of Denmark (DTU) validated and implemented a model to simulate future offshore wind power generation and prediction profiles for **2.3 GW, 3.0 GW and 4.0 / 4.4 GW for the Belgian offshore zone**.
- **In the framework of the MOG 2 study update (2022)**, DTU validated and used its model based on **latest meteorological data** (up to 2021), generation profiles (full 2.3 GW offshore), the new commissioning calendar (**5,8 GW by 2030**) and an update of **technology assumptions** (towards 2028-30)
  - *Assumptions were presented by Elia in the TF MOG 2 of April 1, 2022*
  - *Stakeholders input was collected until April 22, 2022 and assumptions were updated accordingly (cf. mail April 29, 2022)*
- **Results of the simulations** were presented by DTU in **the TF MOG 2 of June 24, 2022**
  - *The model is validated and shows a similar / better accuracy compared to the previous study and is therefore suitable for the intended analyses*
  - *The result show similar capacity factors (slightly lower due to higher geographical density), while showing similar ramping and storm characteristics when expressed per unit (= per MW installed)*
  - *Nevertheless, these power variations increase in absolute terms trough the capacity increase from 4.4 GW towards 5.8 GW*
  - *A technical report by DTU with the full results will be published as Annex in Elia's consultation report*
- The simulated generation profiles during storm and ramp events are used in the **real-time system operation simulations for ramps and storms** while the generation and prediction time series are used for **the reserve capacity projections**

Impact on Elia's reserve capacity needs

Impact on Elia's reserve capacity needs

Scope

Update on Elia's expectations on future reserve needs and balancing capacity procurements*

Objectives

I. ***Analyze the effect of 5.8 GW*** *offshore on the system's* ***reserve needs***

II. ***Analyze pre-conditions*** *of the market to manage reserve needs and costs*

- **On regular basis, Elia publishes projections of its reserve capacity needs**. The latest projections are:
  - *MOG 2 study (2020) : presentation of reserve needs evolutions under best, worst and reference scenarios*
  - *CCMD value model (2022) : update of best (full CCMD) and worst (no CCMD) scenarios*
- This **workstream aims to update all projections** (best, worst, reference) in an integrated way **based on latest system observations** (system imbalances and forecast quality) and **expected system evolutions** (MOG 2)
  - *Results will be used as input for minimum available flexibility when assessing the mitigation measures for storms and ramps*
  - *Updated worst and best case scenarios will be used for updating the CCMD value model calculations*
  - *Reference case scenarios (best estimates) will be used in adequacy studies (e.g. Adeqflex 2023)*
- This exercise should also be seen in the framework of the request of stakeholders towards market stability and previsibility. The projections are only indicative as real reserve capacity needs and balancing capacity procurements are determined by the **methodologies approved in LFC block operational agreement and LFC Means, approved by CREG after public consultation**.

*** Remarks :**
- *Less relevant for the MOG 2 OWF tender but large impact on real-time system operation and costs*
- *Impact on system flexibility needs is kept outside the scope as the 5.8 GW was covered by 'high RES' scenario in the last Adequacy and flexibility study 2022-32 and analyses will be updated in the upcoming Adequacy and Flexibility study 2024-34 (June 2023)*

Impact on mitigation measures for storms and ramps

Impact on mitigation measures for storms and ramps

Scope

Update of real-time system operation simulations

Confirm or amend proposed mitigation measures impacting the MOG 2 OWF tender

- *High wind speed technologies*
- *Preventive curtailment*
- *Ramp rate limitations*

Objectives

I. ***Investigate how the expected impact on the system*** *impacted by increasing the capacity to 5.8 GW*

II. ***Investigate if the proposed mitigation measures still adequate*** *in a 5.8 GW offshore context*

- Objective is to **update the simulations on real-time system observations** with latest observations and expected system evolutions, confirm the proposed mitigation measures and elaborate on their implementation
  - *This update was requested by the stakeholders in the framework of the MOG 2 study (2020)*
  - *Note that while the initial focus of the study was on confirming the mitigation measures, a context of 5.8 GW requires to consider need for complementing / fortifying the proposed mitigation measures.*
  - *The study aimed to be robust towards new evolutions compared to the 2020 study (CCMD, OBZ, HVDC)*

- The model has been improved and **adapted to latest system evolutions**, while market performance criteria have been revised in view of latest observations.

- As expected, simulations for an installed offshore wind capacity of **5,8 GW confirm that issues may occur during storms and ramps,** as well in the up- as downward direction

- The update confirms the **need for the specific mitigation measures which will impact wind parks and / or concerned BRPs**. For this reason, Elia aims to provide as much transparency on these measures as possible before the MOG 2 OWF tendering

LFC block configuration

LFC block configuration

Scope

Assess the impact of an offshore bidding zone configuration on reserves, system operation and proposed mitigation measures

Objectives

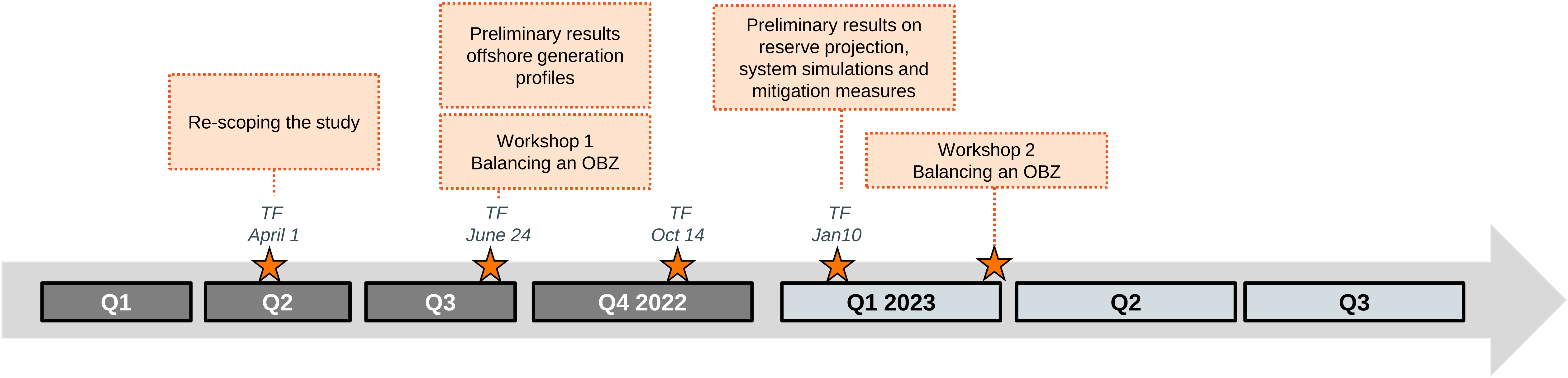
I. ***Analyze the impact on LFC block*** *structure and balancing market organization*

II. ***Analyze the impact on reserve dimensioning****, real-time system operations and* ***recommended mitigations measures***

- **Elia organized a first workshop on the implications of an offshore balancing zone in June 2022**
  - The workshop focused on the general principles of managing reserve activations and imbalance prices in a bidding zone with only generation assets by:
    - Aligning the imbalance price with the offshore bidding zone
    - Avoiding congestion management in the balancing time frame where possible
    - Maintain correct imbalance price signals during congestions
    - Having a cross-border marginal price determined by
    - *European balancing energy platforms of MARI & PICASSO, subject to transmission capacity connected countries*
      - *Activation of flexibility, mainly downward activation of wind, or other flexibility installed (if any)*

  Elia stressed the novelty and complexity of the topic, with no best practices, lacking literature and with a legal framework which requires interpretation for this context
- **Elia received several questions by stakeholders which will be treated in a next workshop on offshore bidding zone focusing on balancing**
  - Only questions related to reserve dimensioning and mitigations measures will be discussed today
  - A more complete presentation on balancing an offshore bidding zone will be provided in the workshop
- **Elia intends to consult an integrated design note on offshore bidding zones in which the balancing aspects are dealt with together with the market aspects**

General planning



- **The analyses presented in this presentation focuses on the commissioning of the full 3.5 GW of wind power by 2030** (with 700 MW in 2028 and 2100 MW in 2029)
- **Elia is analyzing the impact of OBZ and HVDC concepts in parallel.** The results of these analyses will be dealt with in the next workshop and Elia will only touch upon potential implications on the mitigation measures in this presentation

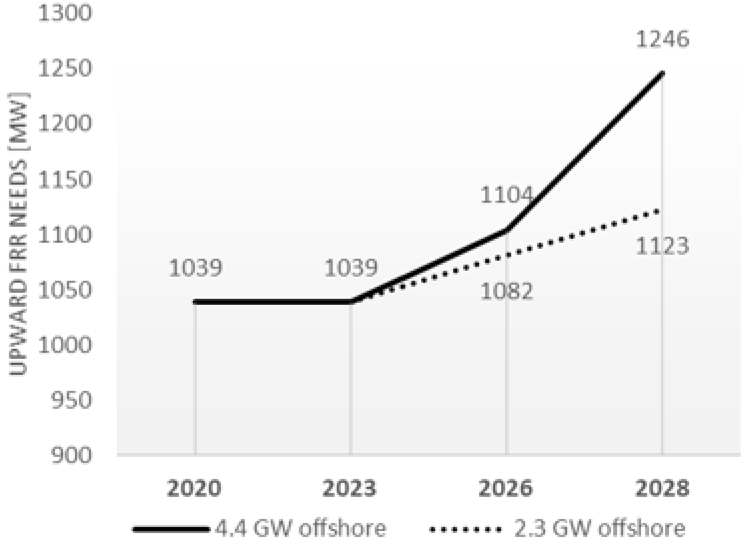
Impact of MOG 2 on reserve capacity needs

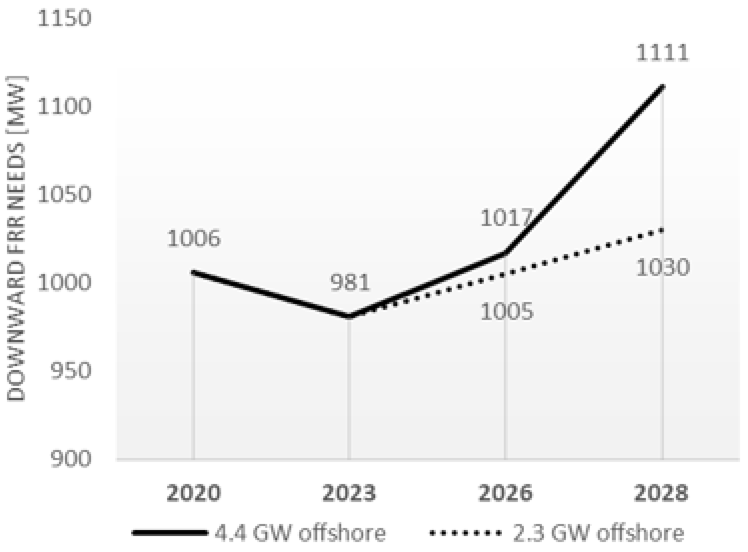
Kristof De Vos

Introduction and reminder study 2020

- **In view of its responsibility to maintain system security and balance the system, Elia dimensions and procures reserve capacity to manage residual imbalances which are not covered by the market**
  - As with the integration of other variable renewable generation such as onshore wind and solar power, the integration of offshore wind power is expected to increase Elia's reserve requirements due to its variability and limited predictability
- **The MOG 2 study (2020) investigated the effect of offshore wind power on the reserve needs :**
  - It concluded that Elia's **reserve capacity requirements are expected to face an increasing trend** following the integration of additional offshore wind power capacity, as well as the increasing capacity of other renewables.
  - It is found that the **market performance** (i.e. the ability of BRPs to balance their portfolio) can substantially impact the future FRR needs
  - A **dynamic dimensioning methodology** will help managing the impact of these increasing needs, taking into account the observed market performance
  - Note that **no specific mitigation measures to limit the effect of offshore wind power on reserves** were proposed except for general measures strengthening the ability and incentive for market players to balance their portfolio.
- **In view of the update of the MOG 2 study, it was decided to conduct a full update the reserve capacity projections** in view of the important impact on the market and system and provide maximal visibility to stakeholders on the expected impact of system evolutions

MOG 2 study (2020)
3.0 GW offshore wind in 2026, 4.4 GW in 2028





Overview of the main conclusions

- The method and assumptions were improved and updated to the latest available observations (forecast data, system imbalances) and latest expected system evolutions (renewable projections, installed generation fleet and grid topology)

Note that this exercise is not exclusively related to the integration of offshore wind power in the system, but also accounts the effect of onshore wind and solar power

- In general, the results confirm the previous trends and conclusions :
  - The FRR needs are expected to increase with additional renewable energy installed
  - The facilitation of delivery of flexibility by existing and new (cf. electrification) assets trough CCMD is expected to have a strong mitigating effect on this FRR needs increase
  - Under assumptions of having a consumer-centric market design, together with the implementation of key enablers (electrification, smart metering…) it is expected that despite high RES integration :
    - Upward mFRR balancing capacity procurement can be reduced compared to today’s levels towards 2030 and might even approach zero for most of the time after 2032.
    - Downward mFRR balancing capacity procurement can continue to be avoided

Overview of the presentation

Reserve dimensioning principles

Methodology and improvements overview

Assumptions & scenarios for reserve needs

Results of reserve needs

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Reserve dimensioning principles

- In line with **Article 157 of the SO Regulation**, **Elia determines the reserve needs (FRR / aFRR / mFRR needs)***
  - *FRR / mFRR needs are dimensioned dynamically, i.e. on a daily basis based on expected system conditions;*
  - *Elia presented in 2020 an implementation plan for a dynamic dimensioning of aFRR needs.*

LFC block operational agreement

FRR needs

aFRR needs

mFRR needs

- **DET N-1** : dimension minimum reserve capacity needs on largest deterministic incident (forced outage generator or HVDC-interconnector)
- **PROB99** : dimension minimum reserve capacity needs on probabilistic analysis of expected imbalance risk following forced outages and prediction errors
- **HIST99** : dimension minimum reserve capacity needs on statistical analysis of historic system imbalances

+ Reduce reserve capacity needs by means of reserve sharing determined by difference between DET N-1 and HIST99*
(capped to 30% of the DET N-1 for upward reserve capacity)

- In line with **Article 32 of the EBGL**, **Elia determines in its LFC Means the optimal provision of reserve capacity** taking into account sharing of reserves, the volumes of non-contracted balancing energy bids and the procurement of balancing capacity. This is currently still based on a ‘static’ approach.
  - *Elia calculates on a periodic basis the availability of non-contracted capacity balancing energy bids and the availability of shared FRR capacity;*
  - *Potential ‘firm’ capacity is subtracted from the required mFRR / aFRR needs in order to determine Elia’s balancing capacity (to be procured);*
  - *Elia presented an implementation roadmap of dynamic balancing capacity calculation towards 2027.*

***The methodology is specified in Elia’s LFC block operational agreement (LFC BOA), a document subject to public consultation and regulatory approval**

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Overview of the methodology to make projections of future FRR needs

Scenarios on future BRP ability to balance portfolios

- Assumptions on **ability of BRPs** to balance forecast errors of additional renewable capacity
- Assumptions on **general evolutions of the Elia's LFC block** system imbalances
- Assumptions on **forecast tool improvements**

Projections of future system imbalances

- **Upscaling of historic LFC block** imbalances in view of expected forecast errors of renewable capacity
  - *Based on projections on the installed wind and solar power*
  - *Based on time series of historic forecast errors*
- Accounting **evolutions on forced outages** of conventional generation units and relevant transmission assets

Estimations of future balancing capacity needs

- **Estimations** on future **FRR/aFRR/mFRR needs**
- **Estimation** on **balancing capacity requirements** (to be procured)

Improved methodology for making projections of system imbalances

Based on improvement factors determine for each target year

Recurrent formula (iteration)

Expected system imbalances SI in target year T	=	**Expected evolution of system imbalances** following balancing performance of BRP portfolios in year **T-1**	+	**Contribution of additional forecast errors** (FE_i) of new renewable generation for technology i (PV, Onshore, Offshore) installed between year **T-1 and T**	x	**Expected share of the additional forecast errors** of technology i covered by reactive balancing
SI_T		$X_T * SI_{T-1}$		$\Delta\, IC_{T,T-1} * FE_{0,i} * Y_{T,i}$		$Z_{T,i}$
		$(1 - x_T)_i$		$(1 - y_T)_i$		$z_{T,i}$

SI_0 = Observed system imbalances
FE_0 = Observed forecast errors

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Scenarios, evolution and target years overview

Scenarios presented in the MOG 2 study 2020

Worst Case	**Reference case**	**Best case**
0%/y forecast improvement	*1%/y forecast improvement*	*1%/y forecast improvement*
0%/y SI improvement	*1%/y SI improvement*	*1%/y SI improvement*
35% BRP coverage	*50% BRP coverage*	*65% BRP coverage*

New evolutions compared to the MOG 2 study 2020

1. Update of the historic observations / data (observations 2020-21)
2. Update of the simulated offshore wind generation profiles (DTU simulations)
3. **Revision of the projections on installed renewable capacity (Adeqflex ’23 consultation)**
4. Update of the projections on the conventional generation fleet (Adeqflex ’23 consultation)
5. Revision of the direction schedule projections of Nemo Link (latest estimations)
6. Revision of generator outage probabilities (Adeqflex ’23 consultation)
7. **Integration of MOG 2 grid design (Federal Development Plan)**
8. **Revision of the market performance indicators (latest estimations)**
9. **Expected impact of an offshore bidding zone (high level analysis)**

Presented in full report (items 1, 2, 4, 5, 6)

Presented in next slides (items 3, 7, 8, 9)

Projections

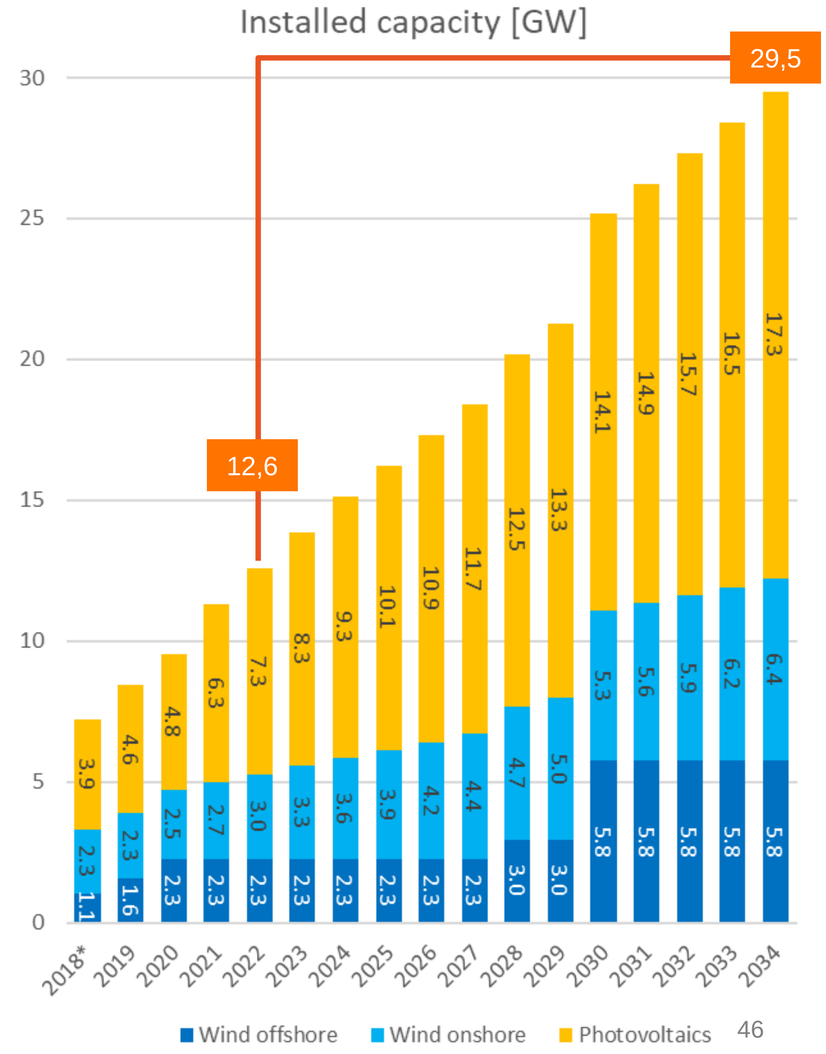
- 2024
- 2025
- ⋮
- 2034

Update - revision of the projections on installed renewable capacity

Projections on installed renewable capacity is based on latest available data (consultation on the Adequacy and Flexibility study 2023) including :

- **Additional offshore generation** as from 2030 (**+1.4 GW**)
- **Increase** speed of **photovoltaic power developments** (**+ 1.6 GW** in 2023 and even **+ 3.5 GW** in 2032)
- **Additional onshore wind** as from 2026 (**+ 0.6 GW** in 2030)

> - **General upward pressure on reserve capacity requirements**
> - **Effect of offshore wind comes later in time (as from 2028 instead of 2026)**



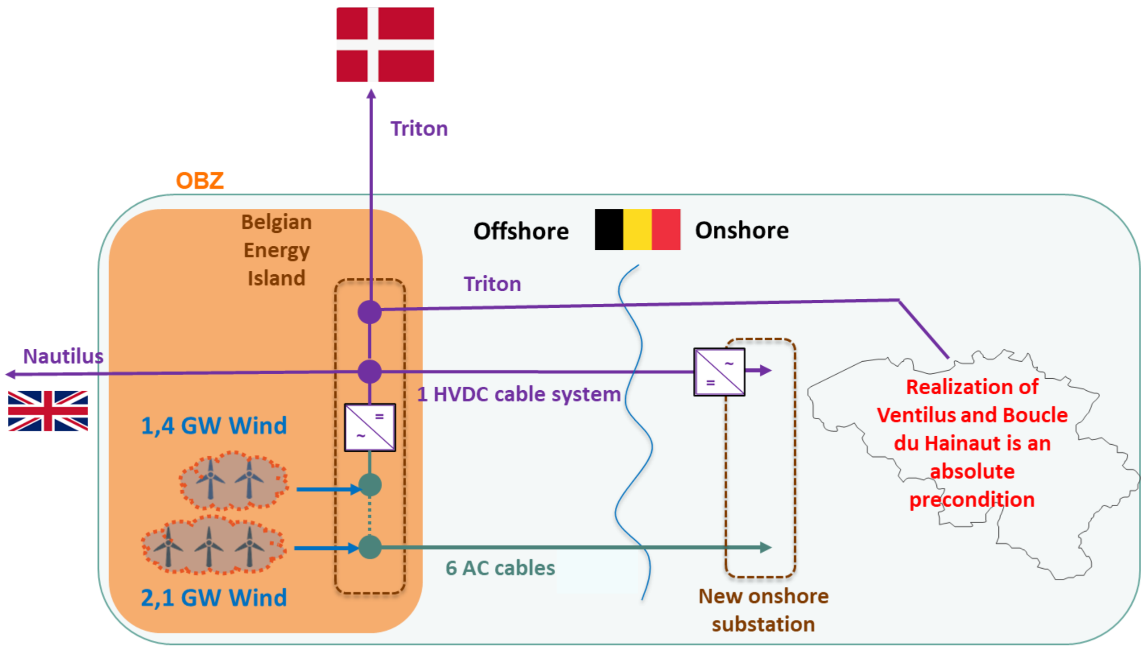
*Source : Adequacy and flexibility sitdy 2023 - public consultation

Update - Integration of MOG 2 grid design

- **Current design options for Nautilus / Triton*** ensure that probability of losing more than 1000 MW remains well under probability levels currently accounted as dimensioning incident
  - HVDC cables will be foreseen with a metallic return substantially reducing the probability of losing the full capacity.
  - HVDC convertor stations will be equipped with configurations (2 poles) that reduces the probability of losing the full capacity
- The **probability of losing more than 1000 MW** only becomes unacceptable when coupling both HVDC systems (MOG2/Nautilus & Triton link) on the island. By design the coupling will only be implemented in presence of a mean to automatically open the coupling after a fault (e.g. HVDC Circuit Breaker) and probability of a losing more than 1000 MW remains sufficiently low.
- **Under normal conditions****, no other grid elements related to MOG 2 (connection of the wind farms to the island, AC connection of the island to shore, onshore grid infrastructure) are expected to impact the dimensioning incident

By design, the forced outage probability* is expected to be far under what is currently accounted as dimensioning incident and allows to justify that the design options considered do **not substantially impact the dimensioning incident in Elia's LFC block**

As foreseen in the Federal Development Plan, Nautilus (as from 2030) and Triton (as from 2032) will be **included in the forced outage simulations in the probabilistic method of the dimensioning** (at potential impact of 50% of their installed capacity following the metallic return technology)



*To be confirmed by the manufacturer

**Analysis is on-going regarding the dimensioning incident in specific situations like long unavailability on the backbone or maintenance at specific places

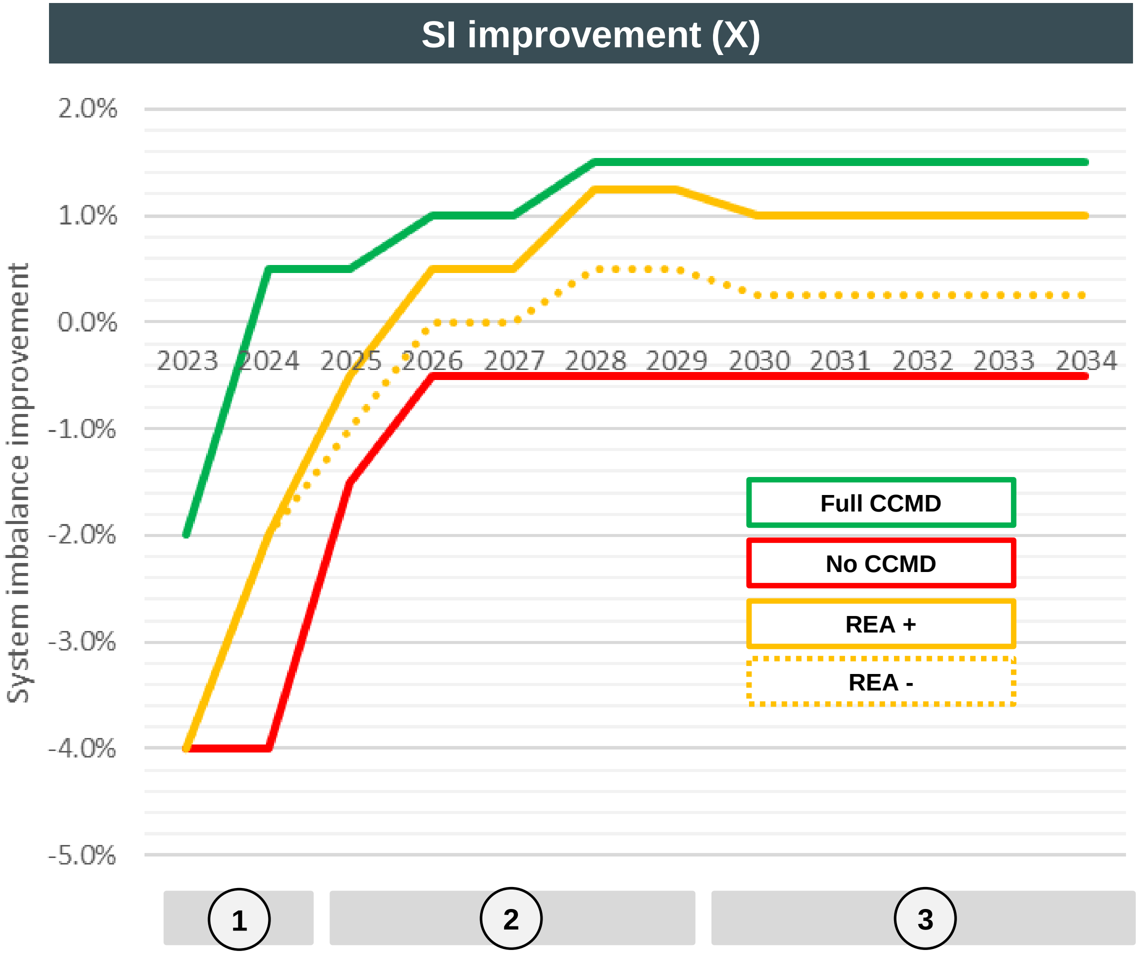
Revision of the market performance indicators

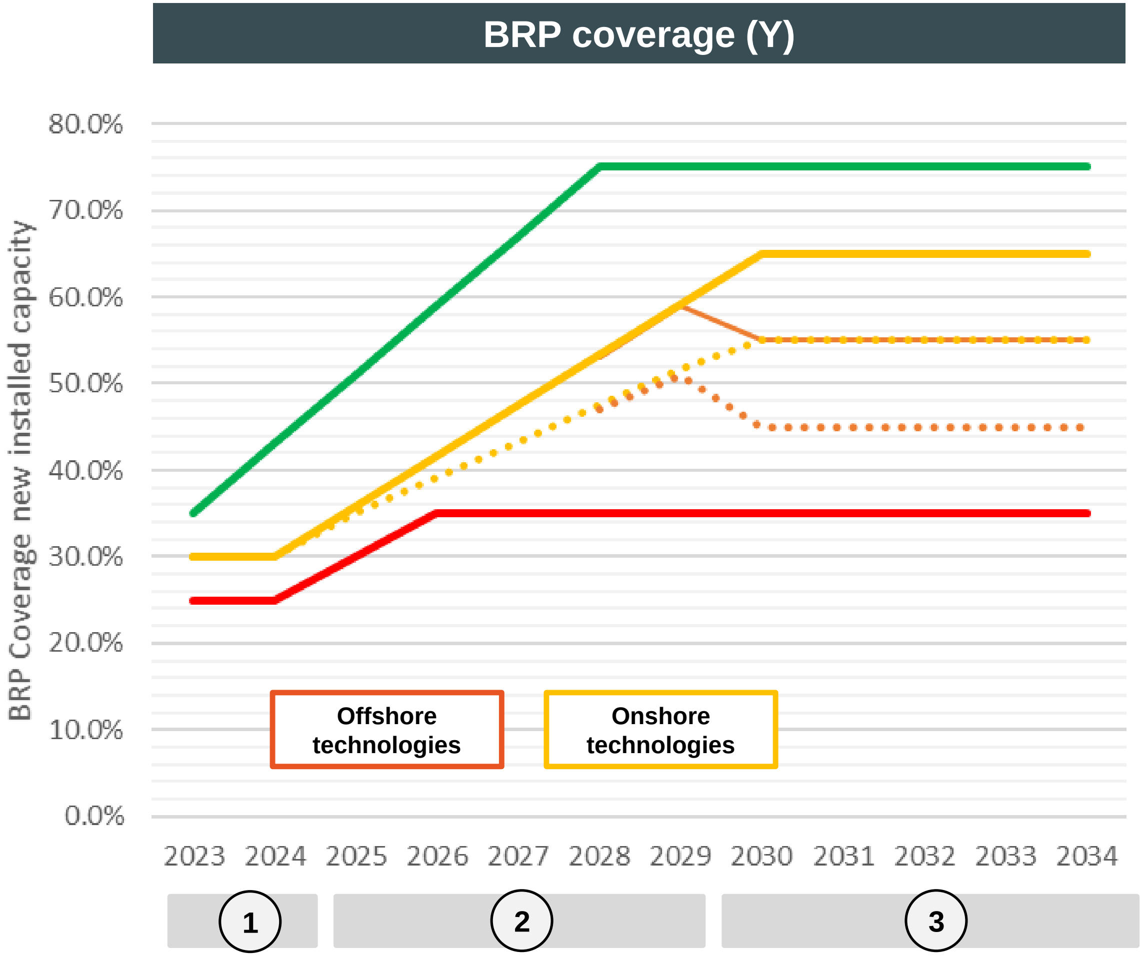
	Extreme scenarios (e.g. used for Elia's CCMD value model)		Best estimates scenarios (e.g. used for Elia's adequacy studies)	
	Worst case scenario (no CCMD)	**Best case scenario (full CCMD)**	**Reference Optimistic (REA +)**	**Reference Pessimistic (REA -)**
General description	No or limited participation of flexible appliances to the electricity markets due to lack of electrification / digitalization/implementation of CCMD. Market players will not be able to balance their portfolio well and the system will largely rely on Elia's balancing capacity procurement and activations	Optimal participation of flexible appliances to the electricity markets thanks to high electrification / digitalization and full implementation of CCMD. Market players will balance their portfolio and the Belgian balancing area to large extent and relieve Elia's balancing capacity requirements and activations	Most of the effect of electrification / digitalization and CCMD will eventually be in place but comes later in time and to slightly lower extent.	Not all effects of electrification / digitalization will be achieved and the effects achieved come later in time due to limited market reform and/or the deployment of key enablers
Status of CCMD developments (for a large part driven by regulator and stakeholder support)	No CCMD	Full CCMD	Medium (e.g. slight deviation from targeted RTP/EoEB design, investments in data access management lower than ambitioned)	Low (e.g. inadequate real-time price design, use of EoEB limited to some specific use cases).
Status of key enablers (external factors with important impact on success of CCMD, e.g. smart meters uptake, distribution tariff design, integration of smart appliances)	Low development (e.g. EV natural charging only)	High development (e.g. EV smart charging only)	High development	Medium development

Scenario assumptions

Requires minor updates in the assumptions

For info





1

- Large system imbalance observed in 2021 and 2022 (energy crisis). Assumptions are taken on slow / fast sector recovery after energy crisis
- Identified challenges to take up new variable generation following limited visibility. Assumptions are taken on solutions to enhance visibility and transparency

2

- Gradual recovery of the system imbalance and ability to take up new variable generation in portfolio as from 2024.
- Assumptions are taken on the speed of improvements based on progress CCMD realizations

3

- Market performance towards 2034 depends on CCMD vision realization.
- Reduction of market performance when assuming no solutions can be found for reduced reactive balancing possibilities in an offshore bidding zone)

Impact of an offshore bidding zone (high level)

Elia presented its first reflections on the implications of offshore bidding zone for balancing in a workshop on June 24, 2022. It concluded that "*beyond the legal obligations, defining a separate imbalance price area consistently with offshore bidding zone has clear advantage in terms of market and system efficiency.*"

Impact of potentially reduced reactive balancing capabilities

A risk is identified / confirmed of reduced reactive balancing possibilities for BRPs in an OBZ (after intra-day cross-zonal gate closure time)

It is not certain that solutions will be found which can completely mitigate this effect

The reference scenarios therefore take into account reduced reactive balancing capabilities following an OBZ

Note that a partial procurement strategy (foreseen as from 2027) should mitigate the effect on balancing capacity procurement when flexibility is available through EU balancing platforms

Impact on reserve dimensioning methodology

Most straightforward solution identified by Elia (cf. TF 24/6) is to maintain both bidding zones in one LFC block (e.g. with two imbalance price areas / LFC Areas)

This allows to maintain a common dimensioning over the two bidding zones (maximizing benefit of aggregating prediction errors over larger geographical area)

But some **geographical constraints** (due to hybrid interconnector congestions) have to be taken into account in the dimensioning of the reserve needs or calculation of the balancing means, i.e. excess energy during high import conditions This is not expected to result in additional procurements (availability of downward regulation trough wind power)

Elia will continue discussions on the topic of balancing an offshore bidding zone with stakeholders in a second workshop

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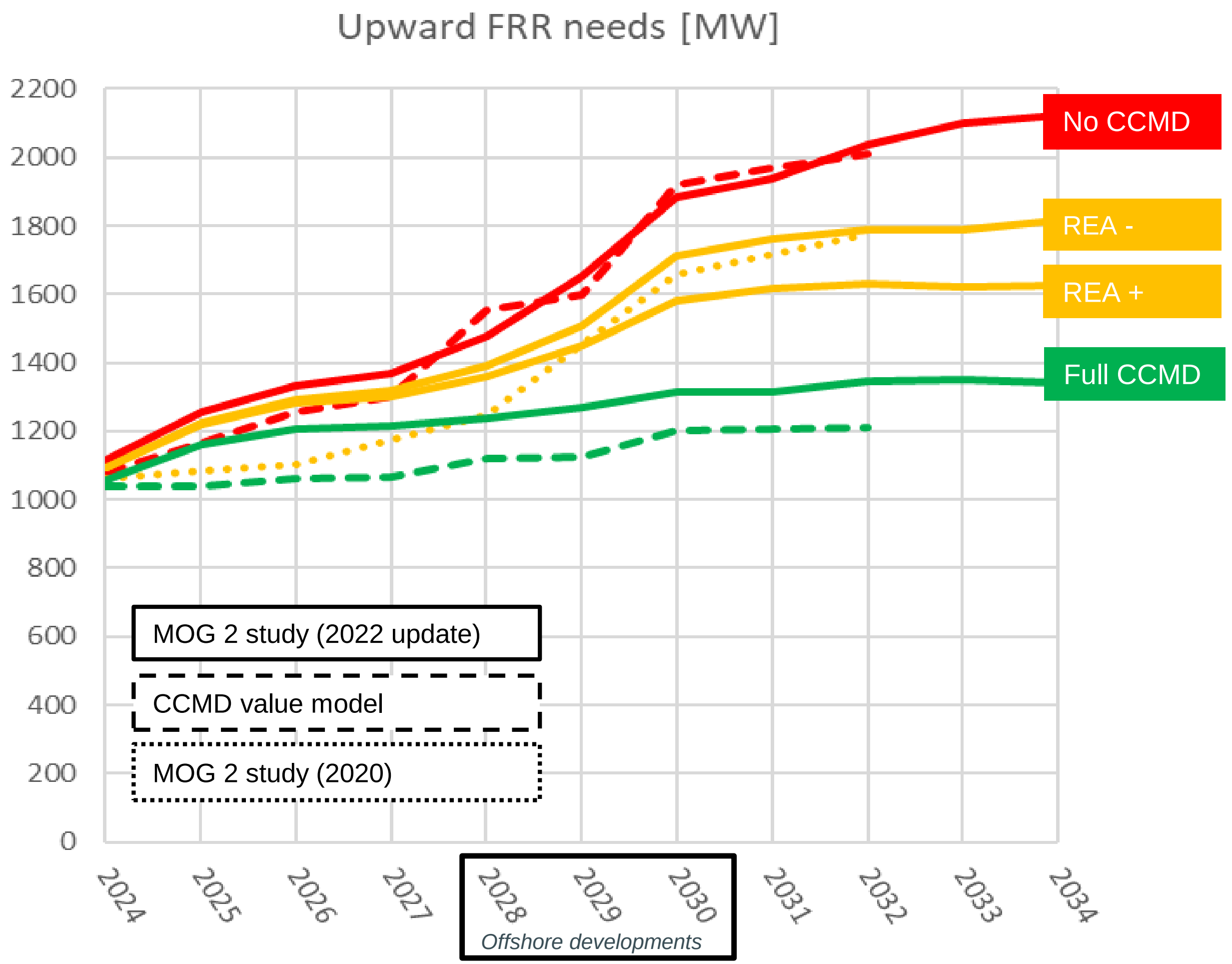
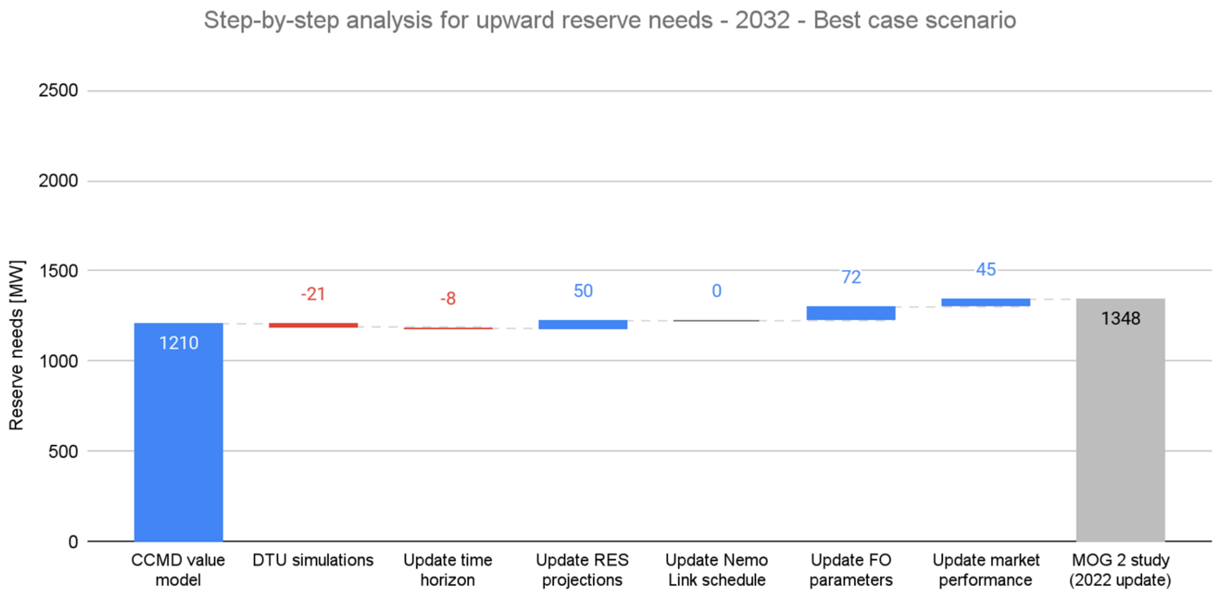
Upward FRR needs projections

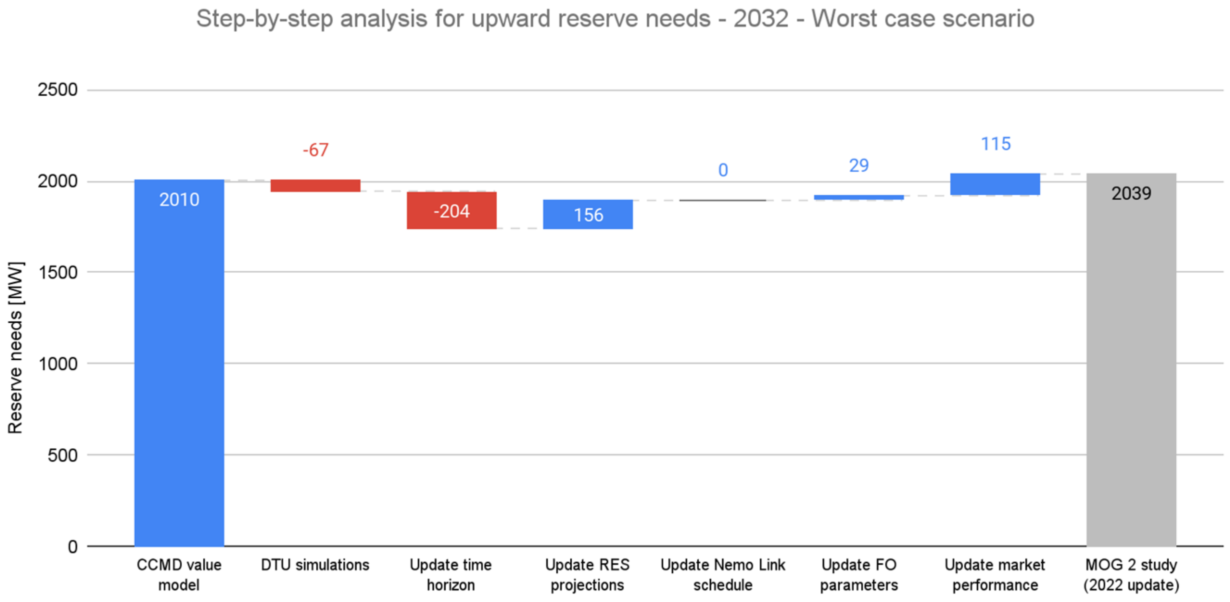


- New projections confirm that in a worst case "no CCMD" scenario, the **reserve needs are expected to more than double towards 2034** following penetration of variable renewable generation.
  - Projections show a prominent effect of the offshore wind developments between 2028 and 2030
  - It is also confirmed that in a best case 'full CCMD' scenario, this increase can be stabilized at an increase of a factor 1.3 towards 2034
- **Projections on the "No CCMD" and "Full CCMD" demonstrate similar trends** as the results presented by Elia in **March 2022 on its CCMD value model**
  - FRR needs increased slightly in a full CCMD scenario, mainly following the implementation of market performance evolutions over time (where largest reduction will come later in time)
- **Elia will consider an Optimistic Realistic (REA+) as a best estimate scenario**
  - FRR needs projections are assumed to be lower as the projections presented in the MOG 2 (2020) study.
  - Without CCMD, or enablers develop slower than expected, Elia will shift projections towards a Pessimistic Realistic (REA-) scenario, close to projections presented in MOG 2 (2020) study

AVERAGE UPWARD FRR NEEDS	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
No CCMD	1059	1118	1258	1332	1371	1475	1655	1886	1937	2039	2102	2121
REA -	1055	1093	1225	1291	1317	1391	1511	1710	1753	1791	1789	1814
REA +	1055	1093	1222	1283	1303	1360	1450	1583	1607	1630	1620	1627
Full CCMD	1044	1056	1162	1208	1215	1237	1271	1314	1315	1348	1352	1342

In depth (1) : evolutions of compared to latest projections



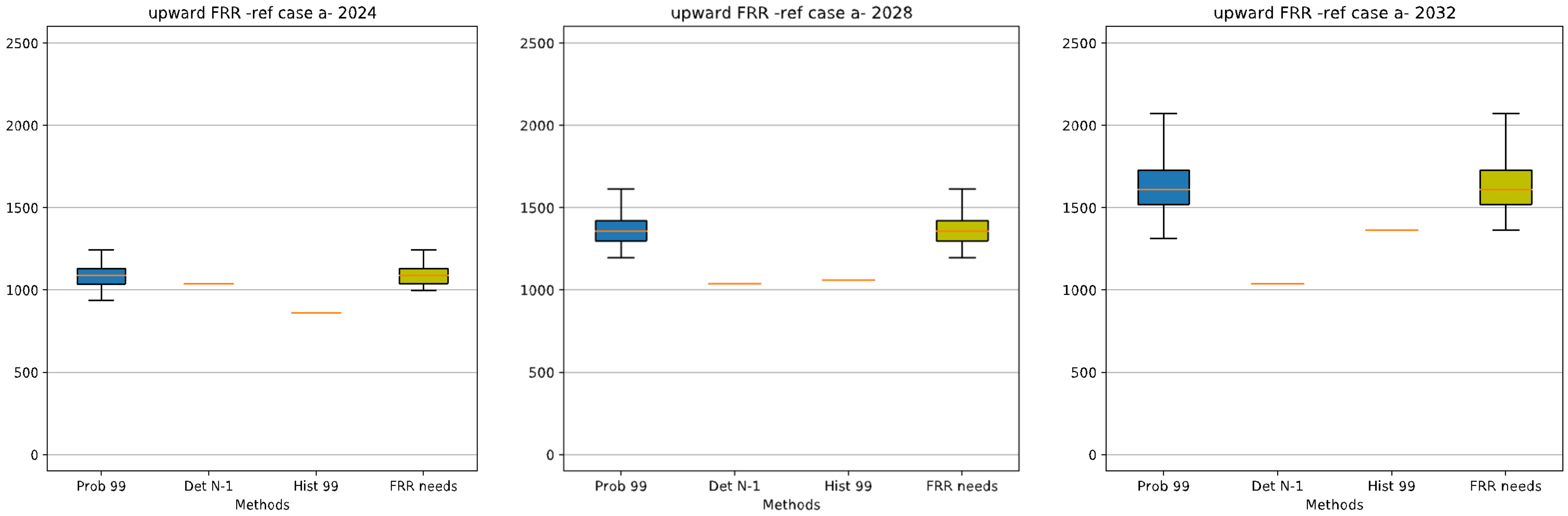


- The **upward pressure of higher renewable ambitions** on reserve capacity requirements is confirmed
- Updated **forced outage statistics** (higher forced outage probabilities assumed for CCGT, cf. consultation adequacy and flexibility study) and improvement **market performance assumptions** (with higher improvements coming later in time) explain higher reserve requirements
- Note that the **update of historic system imbalance observations** (post 2.3 GW offshore) reduce reserve capacity requirements which is explained by better performance as the initial worst case assumptions)

In depth (2): expected behavior of the dynamic dimensioning

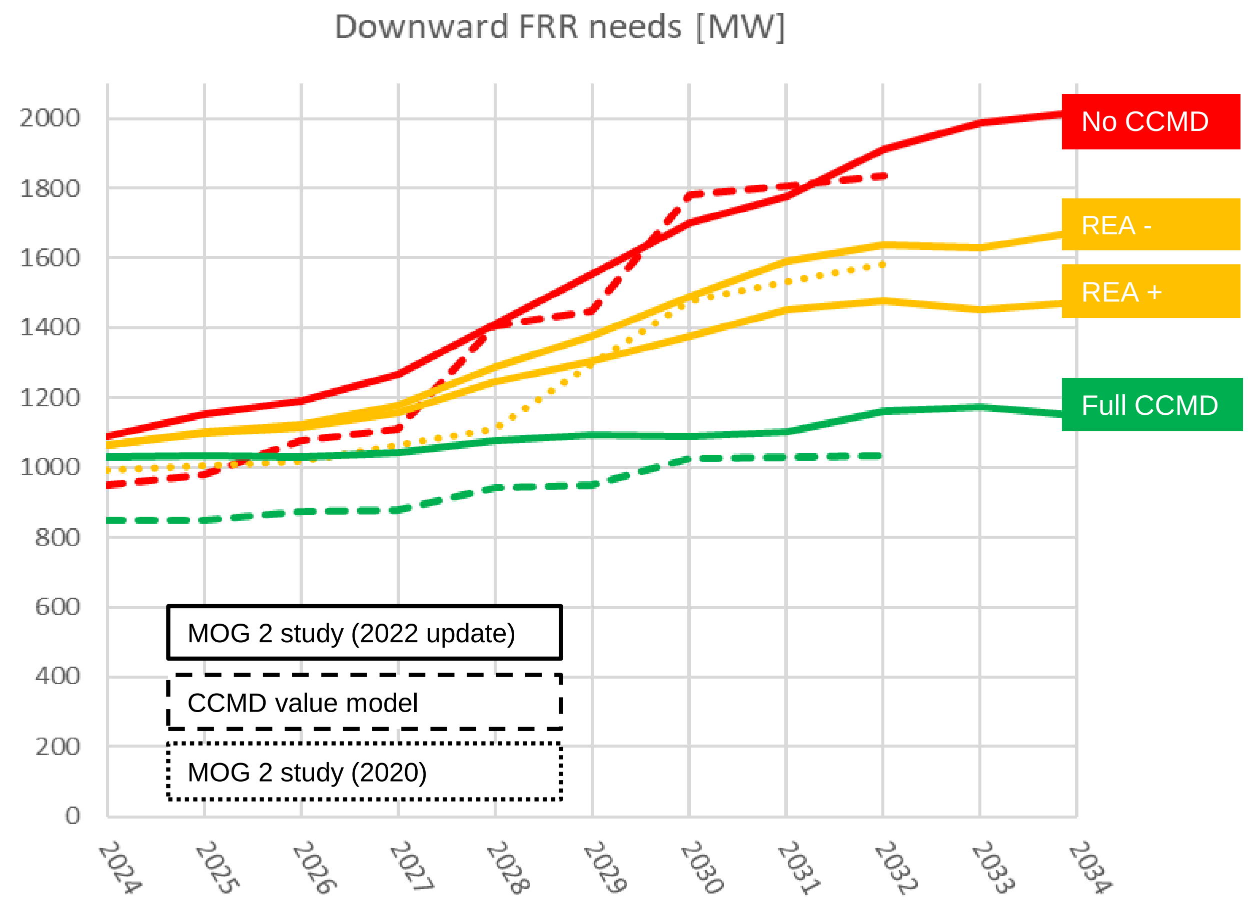
2024, 2028 and 2032 for the REA+ scenario

For info



- **Decreasing impact of the dimensioning incident** on the final FRR needs (and even no impact of dimensioning incident anymore as from 2028) in REA+ scenario
- As from 2028, final **FRR needs are generally driven by dynamic result of the probabilistic method** (demonstrating increasing variability)

Downward FRR needs projections

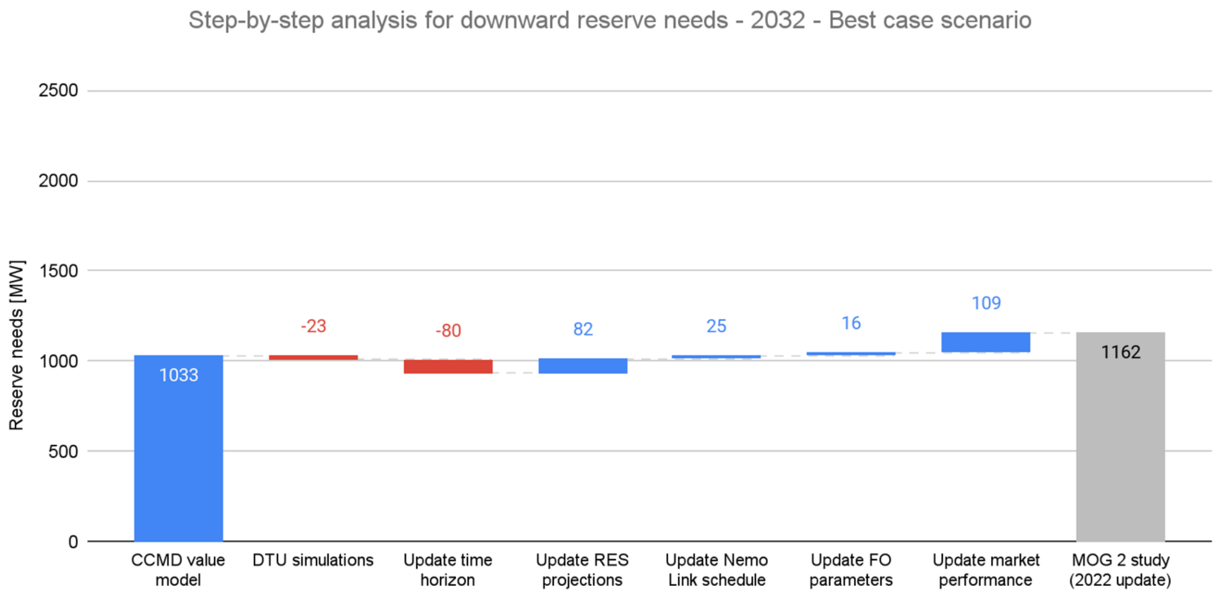


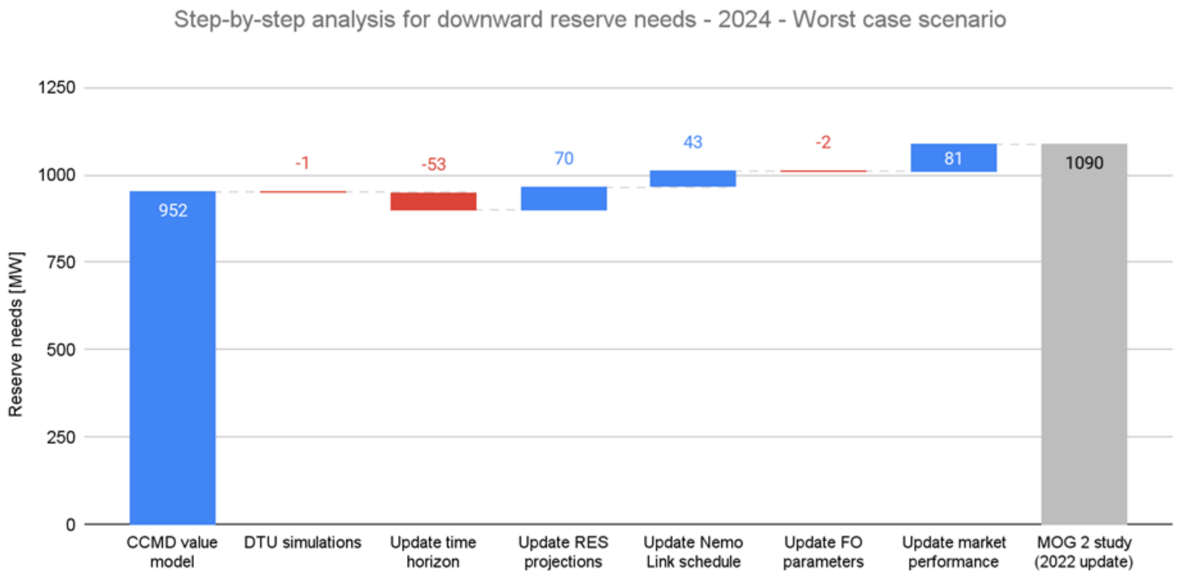
- **In a "no CCMD" scenario, the downward reserve needs projections towards 2034 behave rather symmetrically to the upward side**
  - In such a scenario, reserve needs are driven **by prediction risks of renewable generation** while forced outage risk have limited impact in both up- and downward side.
- **In a "full CCMD" scenario, reserve needs remain at lower level as on the upward side**
  - In such scenario, the **forced outage typically have a larger impact** on the results while these forced outage risk are lower on the downward side (limited to relevant HVDC-interconnectors)

AVERAGE DOWNWARD FRR NEEDS	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
No CCMD	1017	1090	1151	1189	1267	1412	1552	1703	1776	1912	1990	2019
REA -	1012	1062	1102	1123	1178	1287	1376	1491	1589	1639	1628	1674
REA +	1012	1062	1098	1113	1155	1247	1306	1377	1447	1479	1453	1475
Full CCMD	1002	1029	1036	1030	1043	1077	1092	1091	1100	1162	1175	1149

In depth (1) : evolutions of compared to previous projections

For info

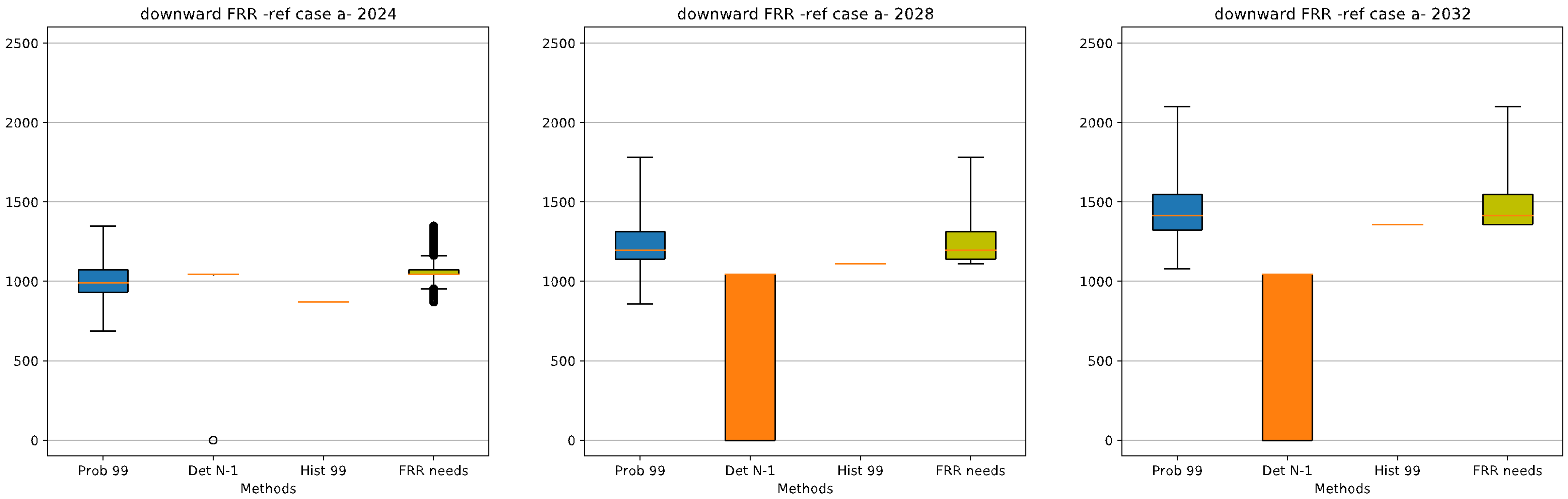




- Similar trends as for upward direction

In depth (2): behavior of the dynamic results

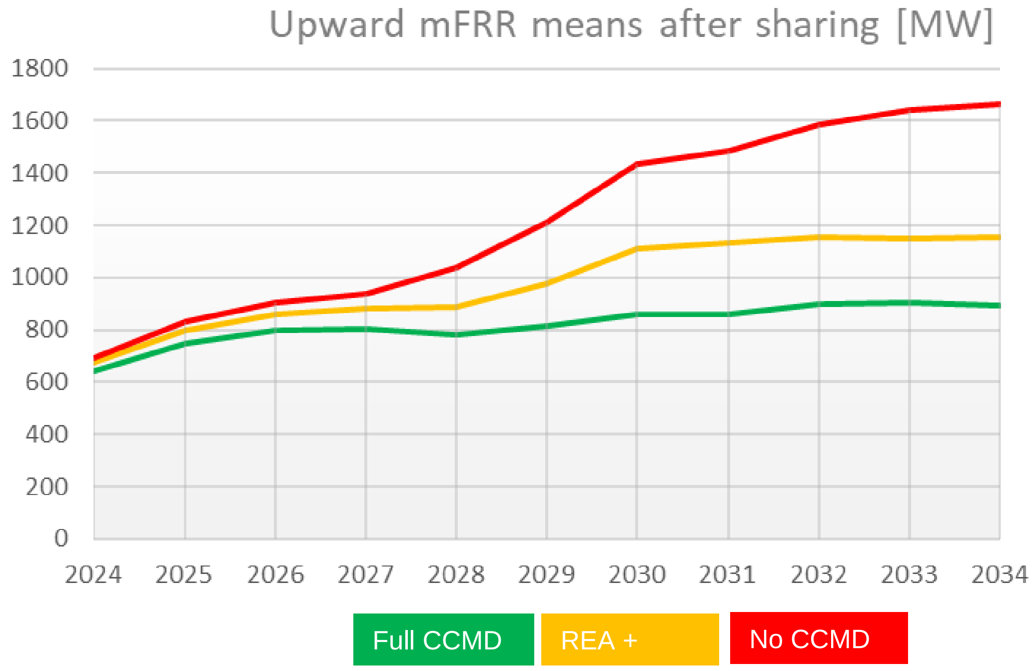
For info

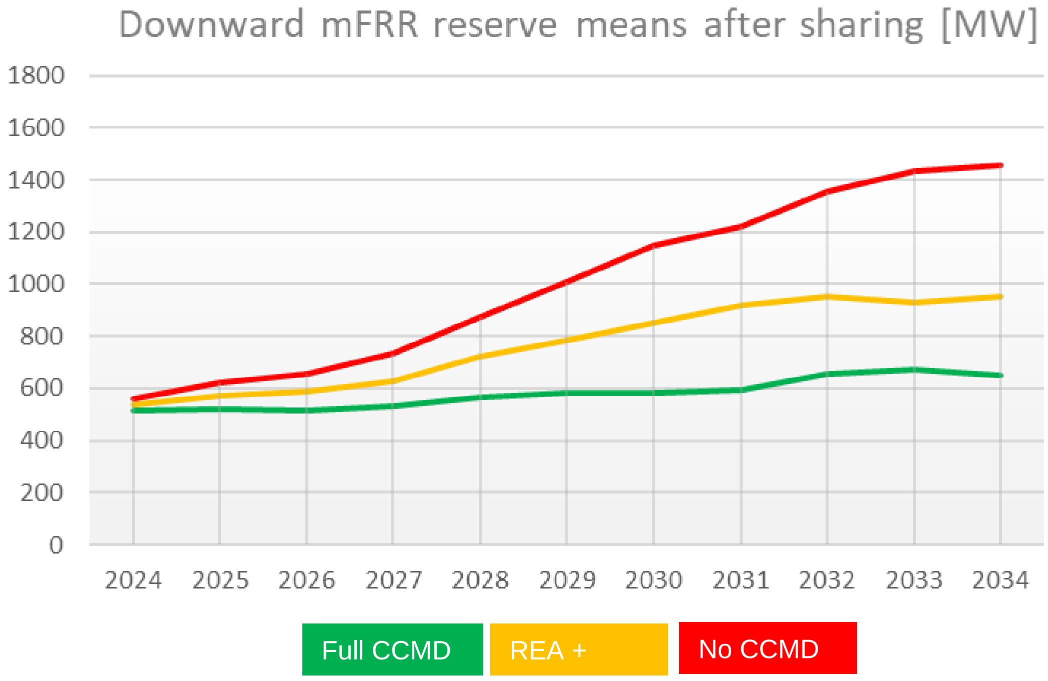


- **Decreasing impact of dimensioning incident** on the final FRR needs (but remaining impact until 2032) in REA+ scenario
- As from 2028, final **FRR needs are largely driven by dynamic behaviour of the probabilistic method** (demonstrating increasing variability)

mFRR reserve means are expected to increase proportionally with the FRR needs

= Capacity that needs to be covered with contracted or non-contracted mFRR balancing energy bids



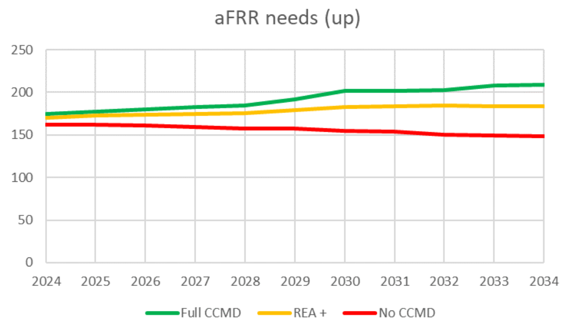


ASSUMPTIONS

mFRR needs = FRR needs – FRR sharing - aFRR needs

- Based on mFRR reserve sharing volumes up to 250 MW / 350 MW for up- downward capacity until 2027, increasing to 300 MW / 350 as from 2028 through the implementation of dynamic sharing together with partial procurement strategies in the Full CCMD and REA + scenario

- Updated of aFRR needs projections in line with FRR projections based on the methodology presented in the aFRR dimensioning study (2020). Note that this methodology is still under discussion between CREG and Elia.

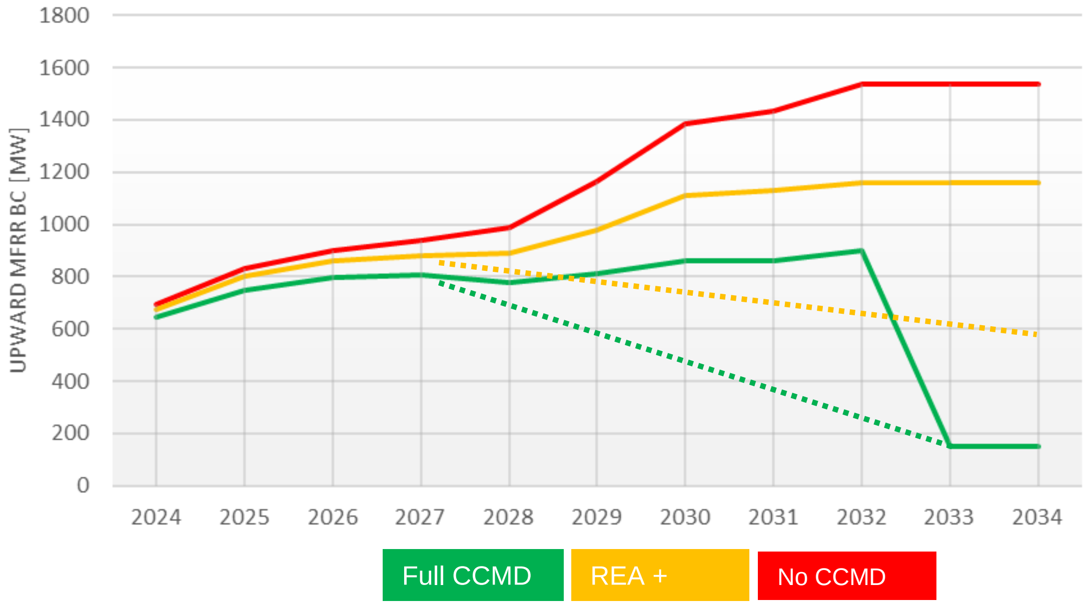


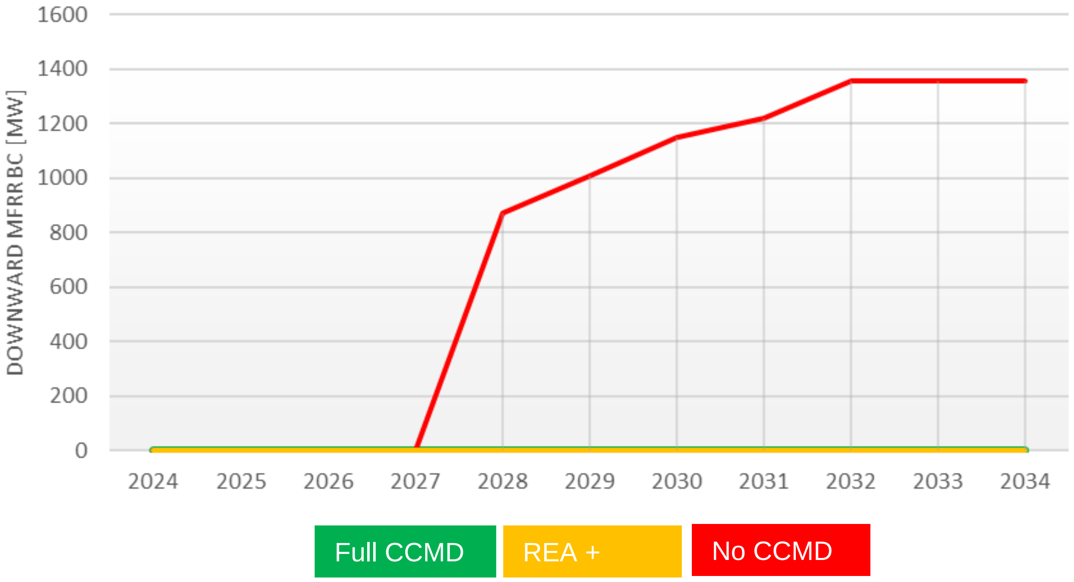
mFRR balancing capacity requirements can be reduced to zero when able to fully account non-contracted balancing energy bids*

Procurement close to zero (most of the time) after 2032 in Full CCMD scenarios

Elia's adequacy and flexibility study shows that in the reference scenario (including participation of some decentral capacity), upward flexibility needs are expected to be operationally covered up to 85% of the time in 2032. ***Elia's ambition is to target full coverage after 2032 and try to avoid upward mFRR procurements for most of the time****.*

Elia's adequacy and flexibility study shows that the downward flexibility needs are expected to be operationally covered for 96%. ***Elia's ambition is to continue to achieve full coverage and avoid downward mFRR procurements.***





Gradual reduction of procurement after 2027 in Full CCMD and REA+ scenario

- Partial procurement strategies allow to gradually reduce mFRR balancing capacity procurement (dotted line - rough estimations)
- Projections need to be refined following next flexibility study based on expected operational flexibility in the system

- No impact as downward mFRR balancing capacity procurement is expected to be avoided in Full CCMD and REA+ scenario

Conclusions and main take-aways

- **Latest reserve capacity needs projections were updated** (used in MOG 2 2020, CCMD Value Model 2022)
    - System imbalance and wind power forecasts 2020-21 (after full commissioning of the 2.3 GW offshore fleet)
    - Latest projections on evolutions of the Belgian generation fleet (Adeqflex 2023)
    - New assumptions on evolutions on market performance (with / without CCMD)
    - Including latest assumptions on MOG 2 (Nautilus, Triton and OBZ)

- By design, **none of the (offshore) grid evolutions is expected to fundamentally impact the reserve needs** through the dimensioning incident

- **Without action, upward reserve capacity needs are expected to almost double to 2 GW towards 2032** following the integration of renewable generation due to its variable nature (with limited predictability)
    - Prominent effect of offshore wind power is found between 2028-2030 in pessimistic scenarios
    - Most optimistic scenarios with electrification / digitalization / CCMD can stabilize increasing reserve needs around 1.3 GW

- **In optimistic scenarios (assuming implementation of Elia's CCMD)**, the system can be expected to operate after 2032 most of the time **with almost no mFRR procurement**. Gradual reductions of upward balancing capacity procurements are already foreseen after 2027 when implementing partial procurement strategies. In the same scenarios, **no downward mFRR procurement is expected to be needed,** even after the integration of the 2nd wave of offshore wind power.

Impact of MOG 2 on mitigation measures for storms and ramps

Aline Mathy

Introduction - The need for mitigation measures for exceptional balancing conditions (assuming 4.4 GW offshore wind power installed) as per Elia study of 2020

2.3 GW *offshore wind capacity*

4.4 GW *offshore wind capacity*

- Elia investigated in 2018 the potential impact of storms towards the commissioning of the first 2.3 GW offshore
- Mitigation measures put in place focused mainly on power shortages following (unexpected) cut-out events following storms
- A **storm mitigations measure** was implemented to follow-up on market response after detection of a storm, and complemented with the potential pro-active activation of flexibility by the TSO if needed
- An **additional measure** has been put in place **to react to imbalance price signals** (alpha-parameter)

- **Elia investigated in 2020** the potential impact of storms and ramp events when extending the offshore generation fleet to **4.4 GW (as foreseen at that time)**
- **It was concluded that additional mitigation measures were needed** to manage the integration of additional 2,1 GW of offshore wind power in the system
- A recommendation of **High Wind Speed technologies** was presented as a good solution to limit the impact of storms to the extent possible
- The storm mitigations measure was extended to a measure for **preventive curtailment** of offshore production in case of expected flexibility shortages and inadequate market response
- **Ramp rate limitations** were put forward to deal with fast and unexpected upward power ramps (including during cut-in phase after storm)

When analyzing and discussing mitigation measures with the market, Elia always followed following guiding principles

1. Elia is responsible for system security and needs to avoid system violations at any time.
2. Mitigation measures are designed to :
   A. imply the least cost possible for society
   B. mitigate cost when market shows good performance and activation of measures can be avoided.
3. Aim for transparency and visibility on the impact for the wind park / BRP

Context and objective of Elia MOG 2 study update (2022)

Impact on exceptional balancing conditions and need for mitigation measures

Scope

Update of real-time system simulations

Confirm or amend proposed mitigation measures impacting the MOG 2 OWF tender

- *High wind speed technologies*
- *Preventive curtailment*
- *Ramp rate limitations*

Objectives

I. ***Investigate how the expected impact on the system*** *evolves by increasing the capacity to 5.8 GW*

II. ***Investigate if the proposed mitigation measures are still adequate*** *in a 5.8 GW offshore context*

The MOG 2 (2020) study includes recommended specific mitigation measures to manage storm and ramps and to be included in the Tender for additional offshore wind (+ 2.1 GW)

→ An update requested by stakeholders before specifying requirements in the Tender
→ Update increased in relevance with the decision to increase offshore wind to 5.8 GW

Objective is to update the simulations with latest observations and expected system evolutions and confirm the proposed mitigation measures

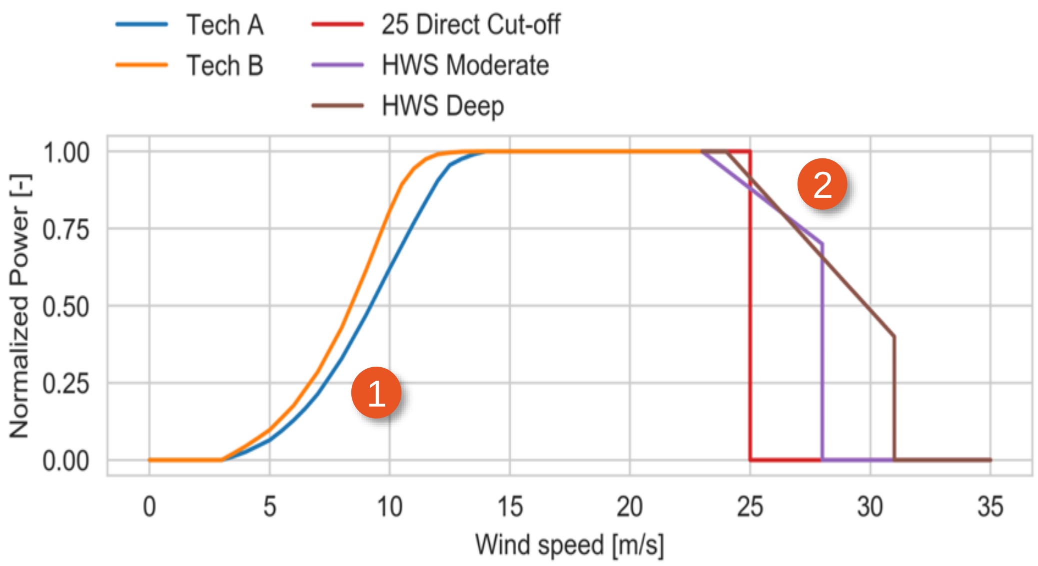
→ Note that while the initial focus of the study was on confirming the mitigation measures, a context of 5.8 GW does not exclude complementing / strengthening the mitigation measures.

The study should be robust towards new evolutions compared to the 2020 study (CCMD, OBZ, HVDC)

When focusing on extreme offshore weather events, 2 relevant cases are identified

1 **Ramps (below wind speeds of 20 m/sec)**
Sudden variation of wind power generation as a result of wind speed variation related to the fast varying profile of the power curve at normal wind speeds.

2 **Storms (above wind speeds of 20 m/sec)**
Sudden variation of wind power generation due to cut-out / cut-in behaviour of wind turbines in case of elevated wind speed related to high wind speed management systems of turbines.



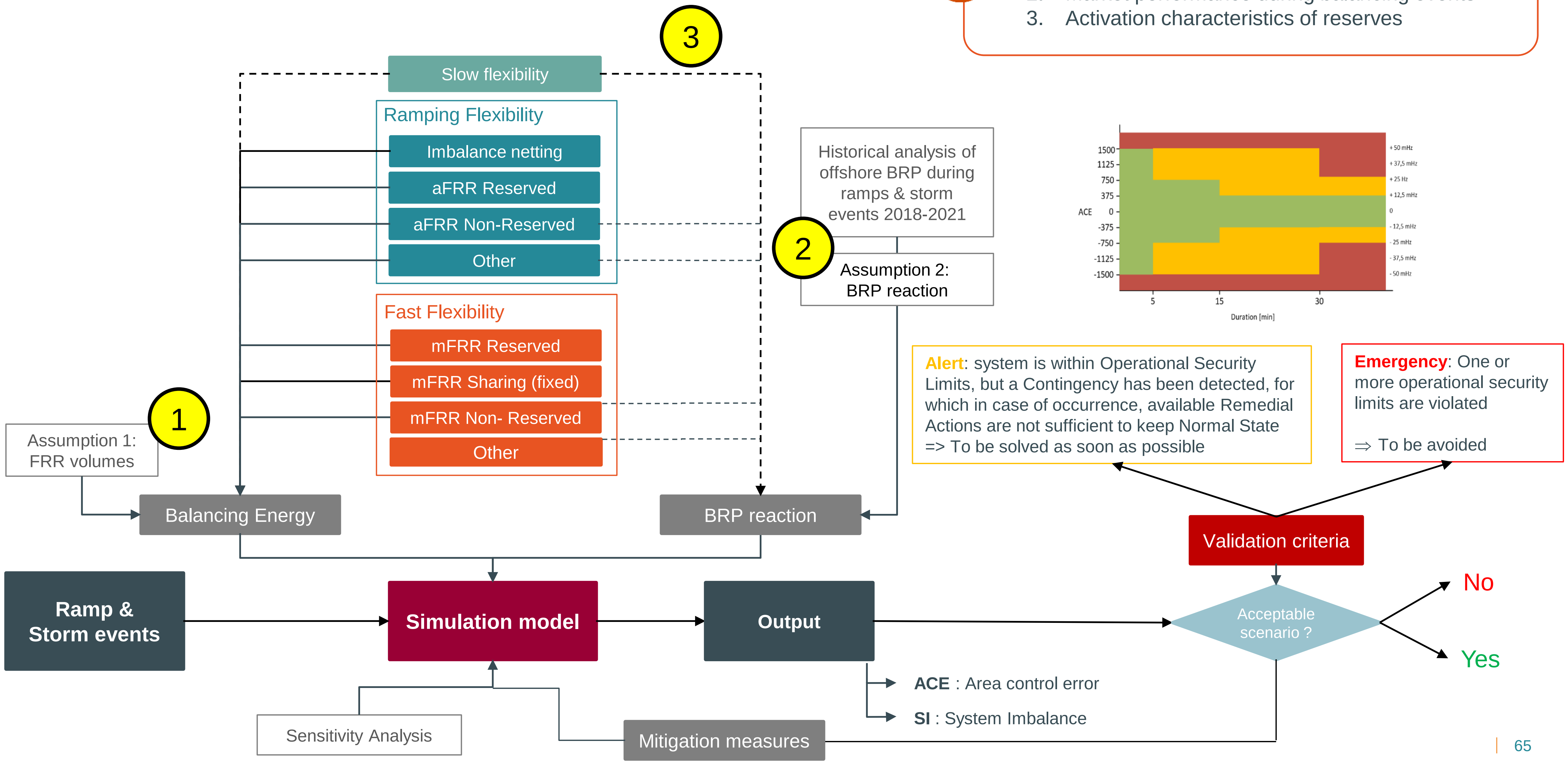
Power curves for assumed technology scenarios and storm shut down scenarios in MOGII integration study

Methodology : Simulation Model

Developed in the framework of the MOG 2 study (2020)

Most important assumptions

1. Availability of flexibility during balancing events
2. Market performance during balancing events
3. Activation characteristics of reserves



1 Assumptions on available flexibility

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MOG 2 (2020)

- FRR needs represent the minimum flexibility which will be available
- Case 1 is aligned with MOG 2 study reserve projections : reference scenario
- Sensitivities with additional flexibility are conducted to account availability of non-contracted balancing energy bids

UP						
		Total FRR	aFRR	Contracted mFRR	mFRR Sharing	Non-contracted mFRR & additional mFRR Sharing
3,0 GW (2026)	Case 1	1104	163	891	50	0
	Case 2	1500				396
	Case 3	2000				896
	Case 4	2500				1396
4,4 GW (2028)	Case 1	1246	177	1019	50	0
	Case 2	1500				254
	Case 3	2000				754
	Case 4	2500				1254

**Additionally, a sensitivity analysis is conducted by adding additional volumes of aFRR to selected cases.*

MOG 2 (2022)

Available FRR in a 5.8 GW offshore scenario	FRR	aFRR**	mFRR
Case 1*	1300	180	1120
Case 2	1500		1320
Case 3	2000		1820
Case 4	2500		2320

**minimum flexibility in the system : total upward FRR needs in best case (full CCMD) scenario MOG 2 2022 study*

***best estimate : based on an update of the projections in the aFRR dimensioning study (2020) following the REA + scenario*

2

Market performance assumptions during extreme events

Calibrated based on observations and future expectations

MOG 2 2020 assumptions (for 4.4 GW)	Ramping event			Storm cut-out		
	Coverage	Full recovery time	Gradient	Coverage	Full recovery time	Gradient
Best case	50%	60 min	2,5%	80%	60 min	2,5%
Worst case	30%	120 min		40%	120 min	

MOG 2 2022 Observations for 2.3 GW	Down Ramping event (shortage)			Up Ramping event (excess)			Storm cut-out		
	Coverage*	Full recovery time*	Gradient**	Coverage	Full recovery time	Gradient	Coverage	Full recovery time	Gradient
Best case	60%	45 min	3,0%	90%	10 min	3,5%	85%	15 min	3,5%
Worst case	30%	130 min		50%	100 min		60%	120 min	

*Average of minimum and maximum over events analyzed in 2020, 21 and 2022
**Average of average over events analyzed in 2020, 21 and 2022

Performance compared to MOG 2 (2020) assumptions: = > <

MOG 2 2022 Assumptions for 5,8 GW	Down Ramping event (shortage)			Up Ramping event (excess)			Storm cut-out		
	Coverage	Full recovery time	Gradient	Coverage	Full recovery time	Gradient	Coverage	Full recovery time	Gradient
Best case	60%	45 min	3,0%	80%	15 min*	3,0%	85%	15 min	3,0%
Worst case	30%	120 min*		50%	120 min*		45%	120 min	

*Values rounded
In red: reduced performance compared to current observations

In general, **observed market performance** (after commissioning of the full 2.3 GW) **is equal or better than first estimations**

But when making assumptions **towards 5.8 GW, it is expected that the performance observed cannot be maintained**, at least without fundamental market reform (CCMD)

3 Methodology key updates

- **aFRR controller is tuned** to larger aFRR activation volumes
- 5 min Full Activation Time (FAT) for all **aFRR reserves activation**, using Merit Order List activation sequence as per PICASSO design
- Improvement of **mFRR activation logic** to capture better operator decisions (Direct / Scheduled activations) following MARI design
- Improvement of **modelling dependence between frequency and system imbalance**.

- Study is based on system imbalances and area control errors resulting from **offshore wind** (compensated by assumptions on available flexibility)
- No fundamental impact on the model is expected when considering an **offshore bidding zone**
- **Uncertainty** on available reserve capacity, BRP ability and topology evolution are captured through **sensitivity analysis**
- There is **no impact assumed on system imbalance** if wind power is connected through **DC or AC**

Overview simulations

Analyse the impact of increasing the installed offshore wind power capacity from 4.4 GW to 5.8 GW

- Based on new simulations presented by DTU

2

	MOG2 2020	4,4 GW Old Assumptions	5,8 GW Old Assumptions	5,8 GW New Assumptions
DTU data version	Old DTU Data	**New DTU Data**	New DTU Data	New DTU Data
Offshore wind power capacity	4,4 GW	4,4 GW	**5,8 GW**	5,8 GW
Technology scenario	Tech B	Tech B	Tech B	Tech B
Storm shutdown scenario	25m/s	25m/s	25m/s	25m/s
Sensitivity on available flexibility	1250-2500	1250-2500	1250-2500	1300*-2500
Activation type	Direct + schedule	Direct + schedule	Direct + schedule	Direct + schedule
Market Performance Indicator version	Old Market Performance Indicator Best / worst case	Old Market Performance Indicator Best / worst case	Old Market Performance Indicator Best / worst case	**New Market Performance Indicator Best / worst case**
Measured impact	MOG II 2020	Impact new DTU Data	Impact volume	Impact new assumptions

1

Validate the impact of model improvements and ensure consistency with previous results published

- Update of the wind generation profiles (no big changes for 4.4 GW scenario)
- Timings for the scheduled activation aligned on MARI requirements
- Scheduled and Direct activations considered simultaneously (Direct Activation was only a sensitivity before)

3

Analyse the impact of expected market performance (reactive balancing)

- Expectation in view of system evolutions

Approach allowed to notice that data behavior was in line with expectations and so to build confidence in data and in hypothesis.

*Aligned with latest reserve projections

Summary of size and occurrences of events

Based DTU simulations – Scenario Tech B & High Wind Speed Deep Technologies

Overview on the size of the 5', 15' and 60' storm and up/downward ramping events observed yearly and over the 10 years based on Tech B and High Wind Speed Deep technologies (considered as a must in the proposed mitigation measures).

Storm

Yearly 15' ID forecast error events of 1.5GW

Cut-out / Ramp down

	Per year	Per 10 years	Maxima
60' events	3GW	3,5GW	3,5GW
15' events	0,5GW	1,5GW	1,5GW
5' events	0,3GW	0,5GW	0,5GW

Cut-in / Ramp up

	Per year	Per 10 years	Maxima
60' events	3GW	5,5GW	5,5GW
15' events	1GW	2,5GW	4GW
5' events	0,5GW	1,5GW	2GW

For all types of events, more critical situations can occur (e.g. cut-out of full 5,8 GW during a storm) over periods longer than 60'

Ramp

Yearly 15' ID forecast error events of 2.5 GW

Cut-out / Ramp down

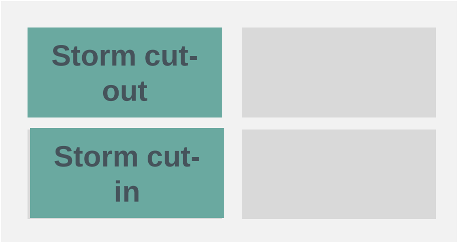
	Per year	Per 10 years	Maxima
60' events	2,5GW	3GW	4GW
15' events	0,5GW	1GW	1,5GW
5' events	0,3GW	0,5GW	1GW

Cut-in / Ramp up

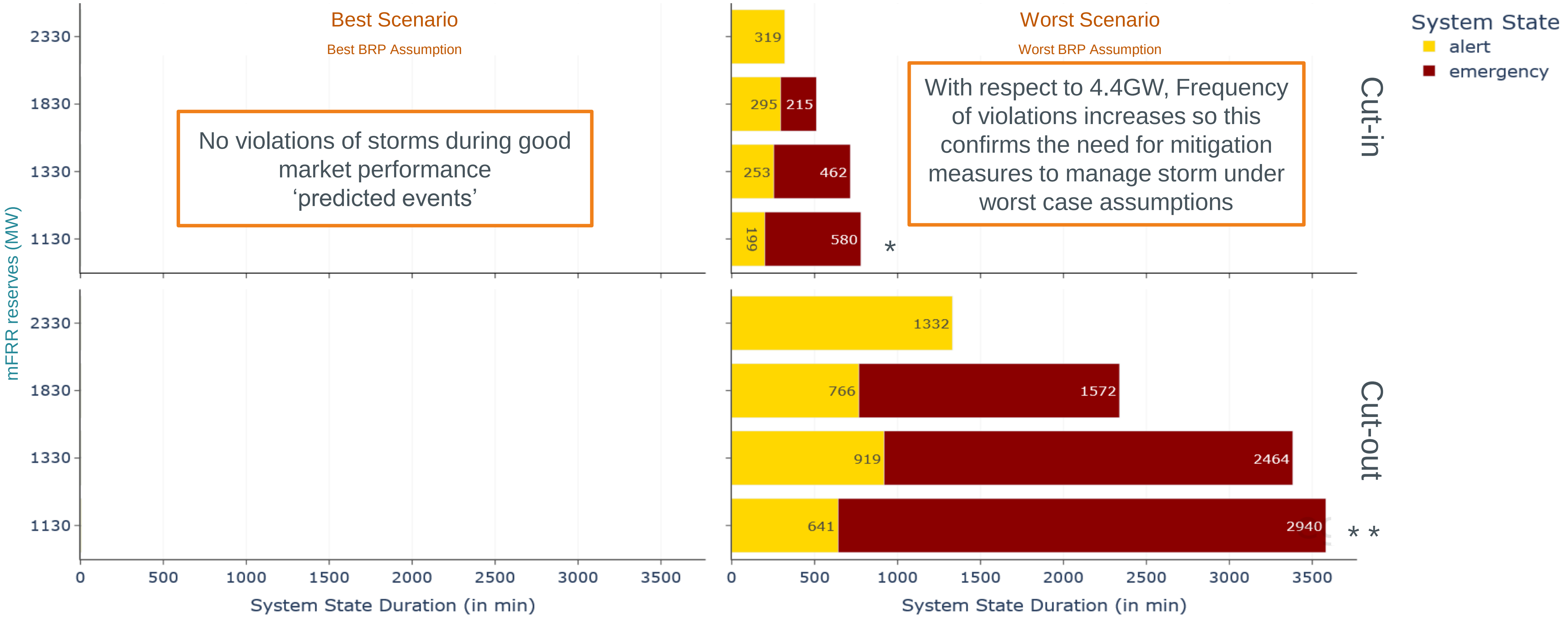
	Per year	Per 10 years	Maxima
60' events	3,5GW	4GW	4,5GW
15' events	0,5GW	1GW	1,5GW
5' events	0,3GW	0,5GW	1GW

Deep HWS technologies (cut-out at 31 m/sec) substantially reduce the frequency and size of cut-out variations and are recommended as minimum technology requirements
Note that these technologies do not reduce the frequency and size of cut-in variations, or may even slightly increase their effect

Total violation duration in each violation class - Storm events



In worst scenario, violations are prevailing especially for cut-out events through the 8 simulated storms



* The total simulation duration for **cut-in** corresponds to **2913** minutes. Hence the emergency in worst case lowest flexibility (1120 MW) is **20 %** of the total simulation duration
* * The total simulation duration for **cut-out** corresponds to **5207** minutes. Hence the emergency in worst case lowest flexibility (1120 MW) is **56.4%** of the total simulation duration

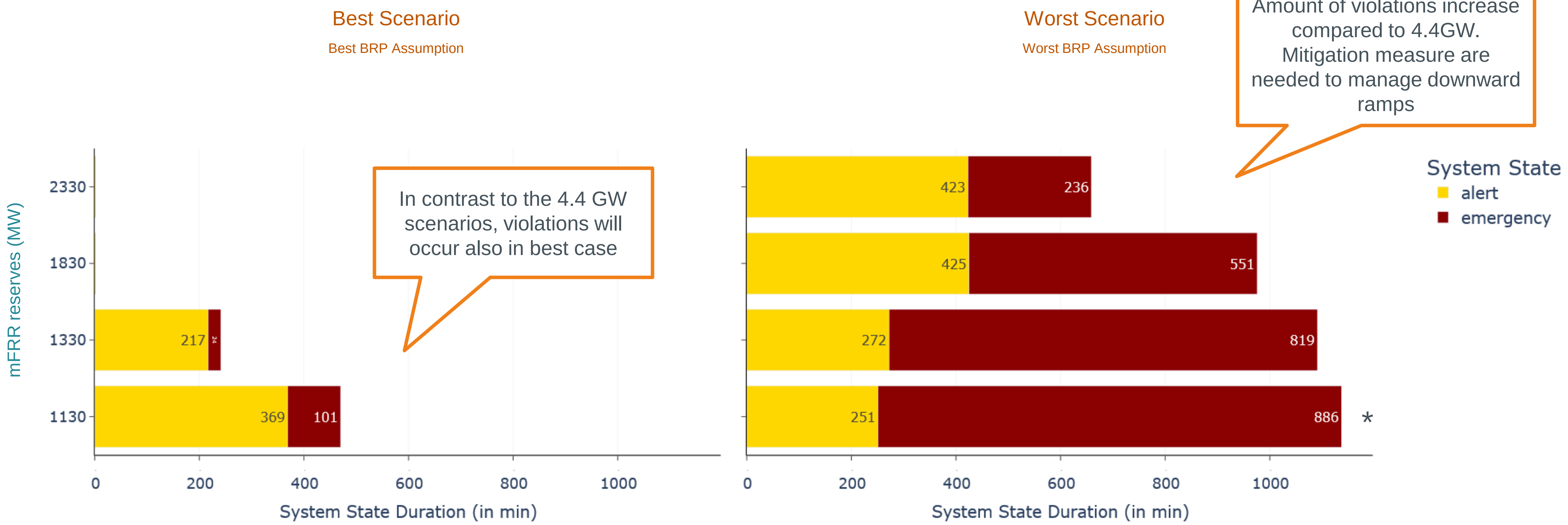
Total violation duration in each violation class - Down ramp events

Ramp down

Violations are observed also for best scenario in case of limited mFRR volumes

Amount of violations increase compared to 4.4GW. Mitigation measure are needed to manage downward ramps

In contrast to the 4.4 GW scenarios, violations will occur also in best case

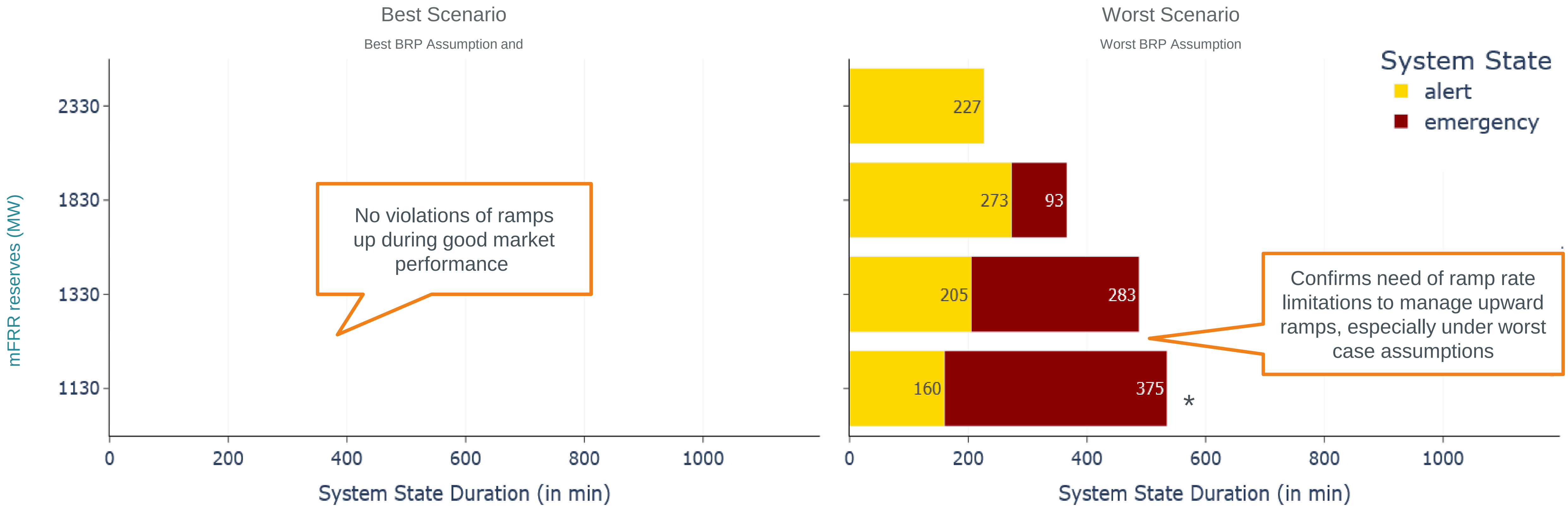


These results identify a need for new mitigations measures to manage unexpected shortages. This issue was not identified in 2020 as upward and downward ramps were treated together.

*The total simulation duration for **ramp down** corresponds to **2548** minutes. Hence the emergency in worst case lowest flexibility (1120 MW) is **34.6%** of the total simulation duration

Total violation duration in each violation class - Up ramp events

Total minutes of violations for 8 ramp events, show emergency violations for most worst scenarios



These results confirm the need for proposed mitigations measures to manage excess energy (ramp rate limitations and cut-in coordination)

*Total simulation duration for **ramp up (25 direct cut-off, no ramping rate limitation)** is of **2194** minutes. Hence, in worst case lowest mFRR reserves (1130 MW) the system would be in emergency for **17.0%** of the total simulation duration

General conclusions of system simulations

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	Storm	Ramp
Cut-out / Ramp down	- **No violations are observed anymore compared to 4.4 GW** under **best case assumptions** (thanks to better market performance assumed) - **Frequency of violations increases under worst case assumptions** through the increase in **installed capacity to 5.8 GW**, even with more flexibility in the system **The results under worst case assumptions confirm the need for the proposed mitigation measures in the MOG 2 2020 study**	- **Amount of violations increases under worst and best case** assumptions due to the increase in installed capacity to 5.8 GW, despite better market performance expected - Violations become also present in the best case - Substantial increase of the violations in the worst case **This creates the need for mitigation measures dealing with downward ramping** **Split compared to previous study**
Cut-in / Ramp up		- **Still no violations are observed under best case assumptions** - **Amount of violations under worst case assumptions remain similar to 4.4 GW** (due to increasing market performance) **The results under worst case assumptions confirm the need for the proposed mitigation measures in the MOG 2 2020 study**

Summary of Mitigation Measures

Not included in present analysis { Existing mechanisms; General actions for investigation by Elia }

Recommended measures with explicit impact on wind power producers and BRPs

	Storm	Ramp
Cut-out / Ramp down	• **High wind speed technologies** • **Current storm procedure** • **Preventive curtailment**	• **New measure to be elaborated (see later)**

CCMD (taken into account in market performance indicators)

Price incentives Real Time Pricing (incl. alpha)

Access to flexibility : Exchange of Energy Blocks

Enhanced forecasting capabilities

Advanced mFRR activations strategies

	Storm	Ramp
Cut-in / Ramp up	• **Ramp rate limitations** • Automatic cut-in coordination for existing parks	• **Ramp rate limitations**

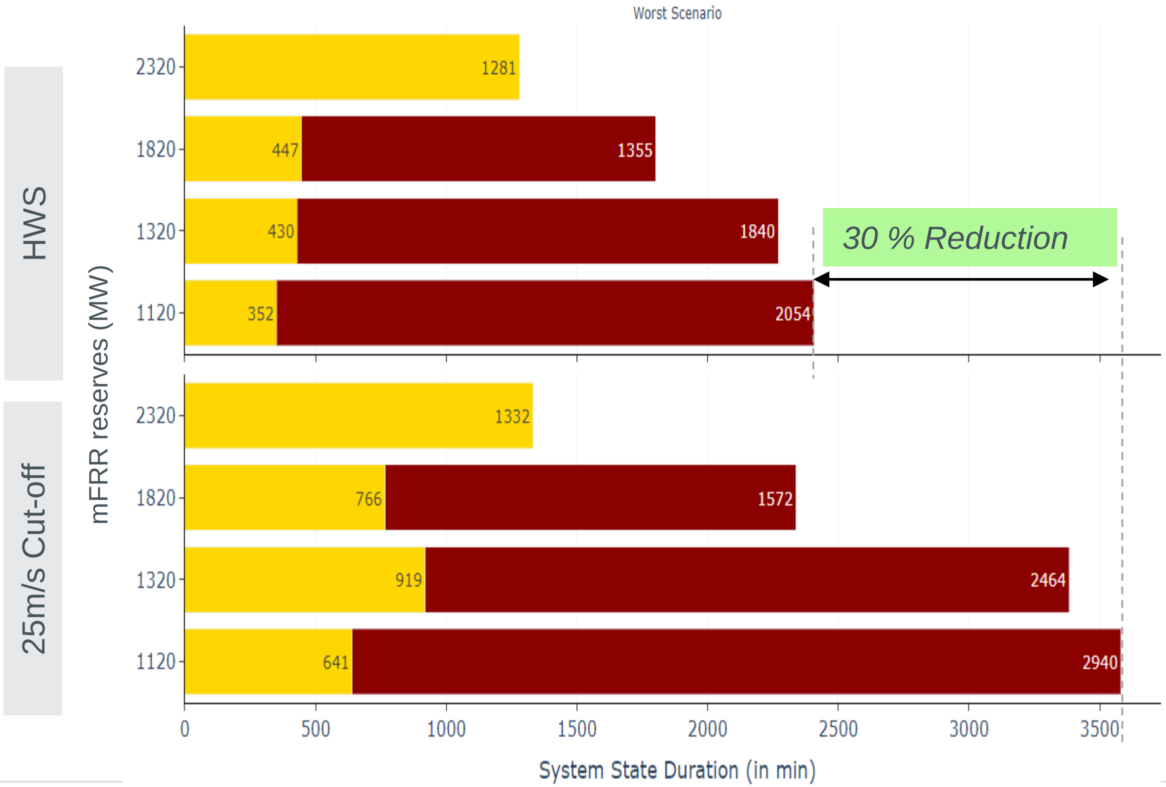
Measures are designed to have as little impact as possible on BRPs / offshore parks when market reacts adequately

Confirmation of need for HWS technologies

Storm Cut-out

HWS technology

- Technological feature for wind turbines allowing to maintain generation until higher wind speeds (31 m/sec)
- Put forward in 2020 study as a solution but does not solve all cases which is why it needs to be complemented with additional measures such as mitigation measure



Emergency violations persist in lower levels of mFRR reserves and last longer for events with a long duration

Conclusions :

- Improvement is particularly valid under worst case market conditions (as there are no violations in the best case)
- Achieved 30 % reduction in term of emergency events, but still substantial amount of violations
- Analyses shows that HWS is particularly useful during the the beginning of the storm cut-out.
- Complementary measures are still needed in worst case market conditions, particularly when considering low mFRR reserves

Confirmation of the need for preventive curtailment

Storm Cut-out

Preventive curtailment

- Mitigation measure allowing to preventively curtail wind power **after forecasted storm event** and **assessment of mitigation measures undertaken by BRPs** (= measure of last resort after market got all opportunities to cover problems)
- Proposed in the MOG 2 study in 2020: to be activated without remuneration for a maximum amount of activations to allow market players to incorporate this risk in their business case

Worst case estimation (based on full curtailment during every storms)

4,4 GW	2 Storms/Year * 7,5 Hours/Storm * 5 Years = 75 Hours/5years
5,8 GW	$\boxed{5}$ Storms/Year * 7,5 Hours/Storm * 5 Years = 187,5 Hours/5years

DTU report: 1.5GW ramp event probability*	
Data	
4,4	5,8
2,1 days/y	4,8 days/y

Considering the same thresholds as in previous study, more storms exceed those thresholds with 5,8GW installed offshore capacity.

Elia Storm tool
Observations
2,3 GW
4,8 storm/y

The need for an activation cap and its parameter will be further discussed in function of the design of the support mechanism.

impact

- Depending on the support mechanism, there might be an impact or not on the lost electricity market revenues upon activations
- Activations may still trigger balancing costs for actors. This uncertainty may result in a risk premium accounted in the strike price
- Elia's projections give market players guidance on the worst case occurrence of these events

*1h ramps down: average number of days per year with at least one event more extreme than the limit of 1,5GW for days with max fleet-level wind speed above 20m/s

New mitigation measure proposed for downward ramps

Ramp down

- **System simulations show that downward ramping events may create unacceptable shortages in the system, as well under best as under worst case market performance**
- **As none of the mitigation measures currently being discussed helps mitigating these issues, specific mitigation measures have to be investigated and discussed**

Preferred solutions

Advanced forecasting tools

Investigate if it is possible to predict variable wind speed conditions.

For example: with the help of the measurements on the parks of other countries

+

B. Extend the storm mitigation tool towards ramping

Day-ahead

Intra-day

Market response

Follow-up on intra-day measures taken by BRPs to mitigate impact on portfolio

Exhausted reserve procedures

Activation of additional **aFRR** flexibility via slow-start units or preventive curtailment

Non-preferred solutions

Increase reserve needs, structurally or on an ‘ad hoc’ basis following advanced forecasting tools

Ramping rate limitation

Storm Cut-in

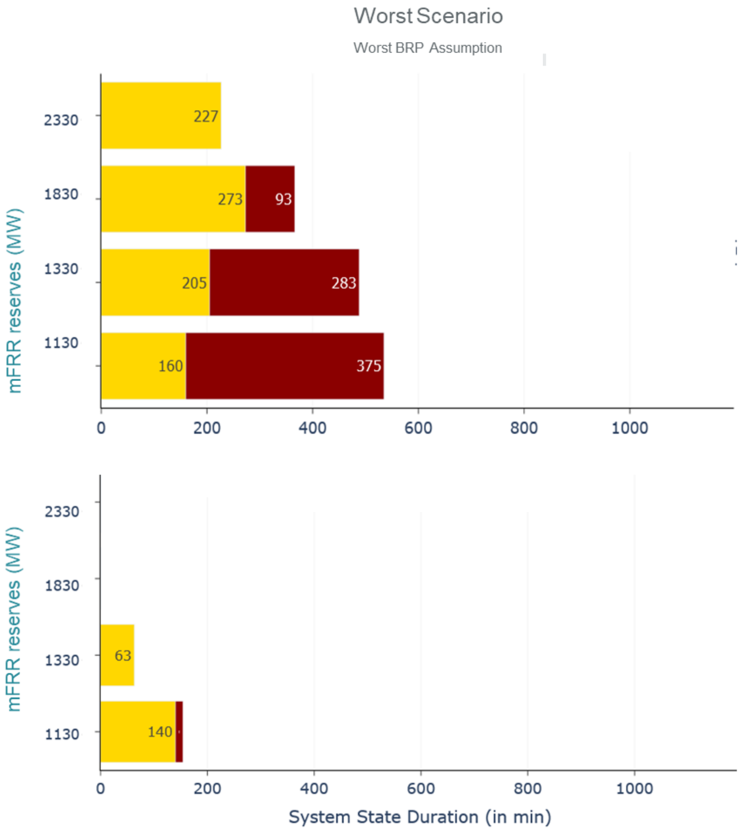
Ramp up

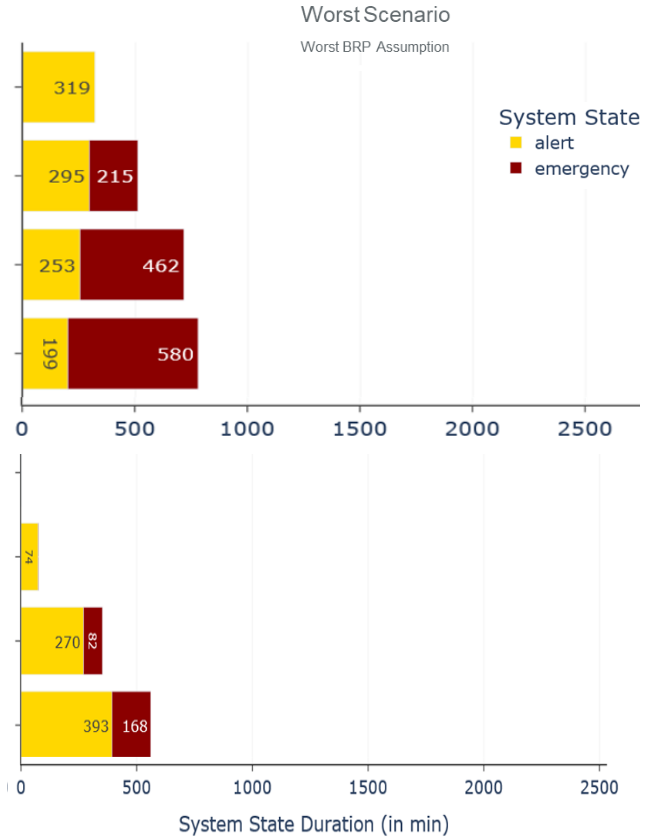
Ramping rate limitation for storm

- Mitigation measure allowing to limit the maximum upward ramp rate when system imbalance exceeds certain values (SI 500 MW; RL 15 MW/min)
- Proposed to be activated without remuneration
- Previous report mentions Elia will update the impact assessment

Without RRL

With RRL *





Storm cut-in

Ramp up

Hypothesis on existing parks

In case of storms, some kind of cut-in coordination of the existing parks remains necessary.

The as-is manual cut-in coordination will be no longer manageable considering increasing system complexity (even more true with 5,8GW)

In case of storms, existing parks can decide to move to ramping rate limitation or to automatic cut-in coordination

Conclusions :

RRL eliminates almost all emergency violations but some remain in worst case and low FRR volumes

Similar conclusions for SI=500 and SI=300 thresholds so we keep the initial proposal of 500MW

More stringent requirements will be needed when facing worst case market performance

* SI 500 MW; RL 15 MW/min

Conclusions

- **The impact of extreme imbalance events on real-time operation is updated for a scenario of 5.8 GW offshore wind power.**
  - The update includes latest validated generation profiles simulated by DTU
  - The update includes alignment of the assumptions with latest (expected) market evolutions
  - OBZ and HVDC concepts are not expected to have fundamental impact on the validity of the conclusions (to be further discussed in the next workshop on balancing an offshore bidding zone

- **Real-time simulations show that control quality criteria are exceeded for storm cut-out / cut-in events, as well as ramp up / down events, particularly under worst case market performance assumptions (i.e. unpredicted events)**
  - HWS remains a good solution, but on its own not sufficient to mitigate fully cut-out effects
  - Preventive curtailment and ramp rate limitations increase in relevance
  - A new requirement is identified to manage downward ramp events with specific mitigation measures or reserve requirements. A potential solution as alternative for increasing reserve needs is put forward for further investigation.

Next steps

- **High wind speed technologies :**
  - Measure confirmed – to be included as technical characteristic in the tender requirements
  - Translation and feasibility of this turbine requirement to a wind park level will be investigated towards commissioning

- **Ramp rate limitations :**
  - Measure and settings confirmed – to be included as technical characteristic in the tender requirements
  - Practical implementation aspects (e.g. communication signals) will need to be elaborated towards the commissioning of the parks
  - Further implementation aspects for automatic cut-in coordination for the existing parks choosing to remain with this mechanism will be developed further towards the commissioning of the parks

- **Preventive curtailment :**
  - Measure confirmed - to be included as technical characteristic in the tender requirements
  - Parameter (cap for unremunerated activation) to be confirmed when having more clarity on the subsidy scheme
  - Practical implementation aspects (e.g. communication signals) will need to be elaborated towards the commissioning of the parks

Today : first discussion with stakeholders
Next: discussion of stakeholders in^put
➜ Full report (subject to consultation)

Note also the ongoing developments (multiple BRPs per access point) and communicated intentions (communications on ability to balance large imbalance risks) on the ability of BRPs to cover imbalances in their portfolio

Workshop MOG 2

10th of January 2023

Market design & OBZ process

Steve Van Campenhout
Thomas Van Den Broucke

| Elia Group

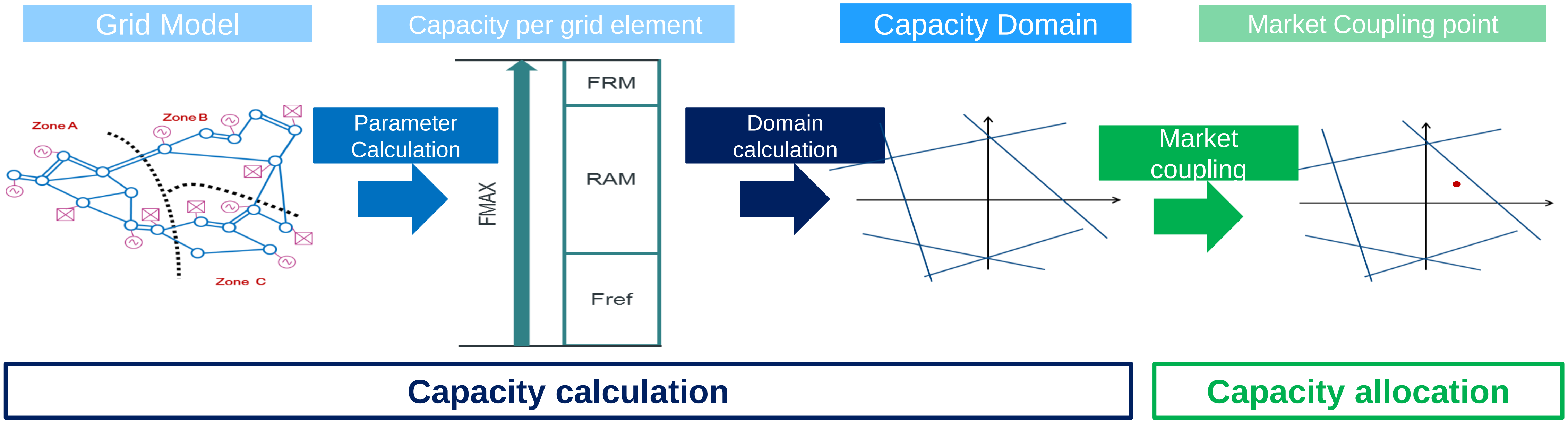
Scope of today's workshop

1. **What is driving the OBZ**
2. **What is driving the scope of an OBZ**
3. **Ideal target model to foster EU's offshore ambition:** UK return to implicit market coupling + offshore bidding zone + advanced hybrid coupling
4. **Legal framework to define OBZ**
5. **Annex:** list of received questions and our answers

1. What is driving the OBZ

General principles of market functioning: capacity calculation

- TSOs have the obligation to **calculate the cross-zonal capacities** available for electricity exchanges **between bidding zones.**
- Day-ahead: capacity calculation starts 2 days < real-time, in order to feed the allocation taking place 1 day ahead of real-time.
- Capacity calculation involves a complex modelisation by TSOs using a series of assumptions: grid, market, weather…
- Regulatory framework to enable a **non-discriminatory, efficient & transparent** approach



Fmax: maximum thermal capacity of the grid element
Fref: forecasted reference flow in the grid element
FRM: flow reliability margin to cover for uncertainties
RAM: reliable available margin = capacity available for market exchanges

General principles of market functioning: capacity allocation

Implicit coupling

- SDAC: single day-ahead coupling = one implicit price coupling across all European bidding zones as implemented today
- Implicit means that cross-zonal capacity & energy (demand and supply) are allocated together to maximize social economical welfare. Capacity is thus made *implicitly* available to the market participants.

Explicit coupling

- Since Brexit the UK is no longer part of the European single implicit price coupling.
- Explicit means transmission capacity and electricity are now traded at two separate auctions. The capacity of each UK-EU interconnector is thus made available in an *explicit* way to the market participants.
- Market participants take decisions based on price forecasts. This sometimes leads to inefficient use of the capacity, meaning electricity flowing from the expensive to the cheaper market.

Role of an offshore bidding zone: manage congestion efficiently

- **Bidding zones form the cornerstone of our European zonal market model**: they are the largest geographical area within which market participants are able to exchange electricity without having to acquire transmission capacity. Within a bidding zone the wholesale market price is uniform.
- Bidding zone borders **must reflect structural congestions** in the transmission network in order to ensure an efficient congestion management and to maximize overall market efficiency.
- When adding an offshore bidding zone, the congestion between the Energy Island and the coast is thus internalized into the market functioning in order to maximize the welfare:
  - Result of allocation: each bidding zone receives a net position that defines how much electricity the bidding zone imports or exports. In an equivalent way this is expressed as how much electricity flows through each bidding zone border (interconnector).
  - By adding an offshore bidding zone there is an additional parameter for the allocation algorithm to optimally match the available cross-zonal capacity with the buy/sell bids of electricity.
- A new bidding zone gives the market an **additional "degree of freedom" to optimize the allocation**.

Role of an offshore bidding zone: manage congestion efficiently

Structural congestion appears when an interconnector is integrated onto the Energy Island.

An **offshore bidding zone** reflects the structural congestion. It allows to efficiently allocate the 3.5 GW transmission capacity between the Energy Island and the coast, thus doing the **economic arbitrage in the market between offshore wind and import through the interconnector.**

Capacity calculation

1 3.5 GW

Transmission capacity BE Energy Island to shore

2 1.4 GW

Transmission capacity interconnector UK > BE Energy Island

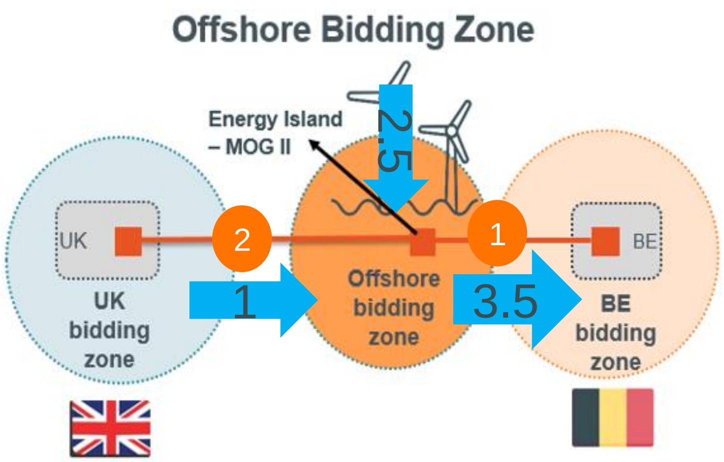
Capacity allocation

Sell bids offshore wind

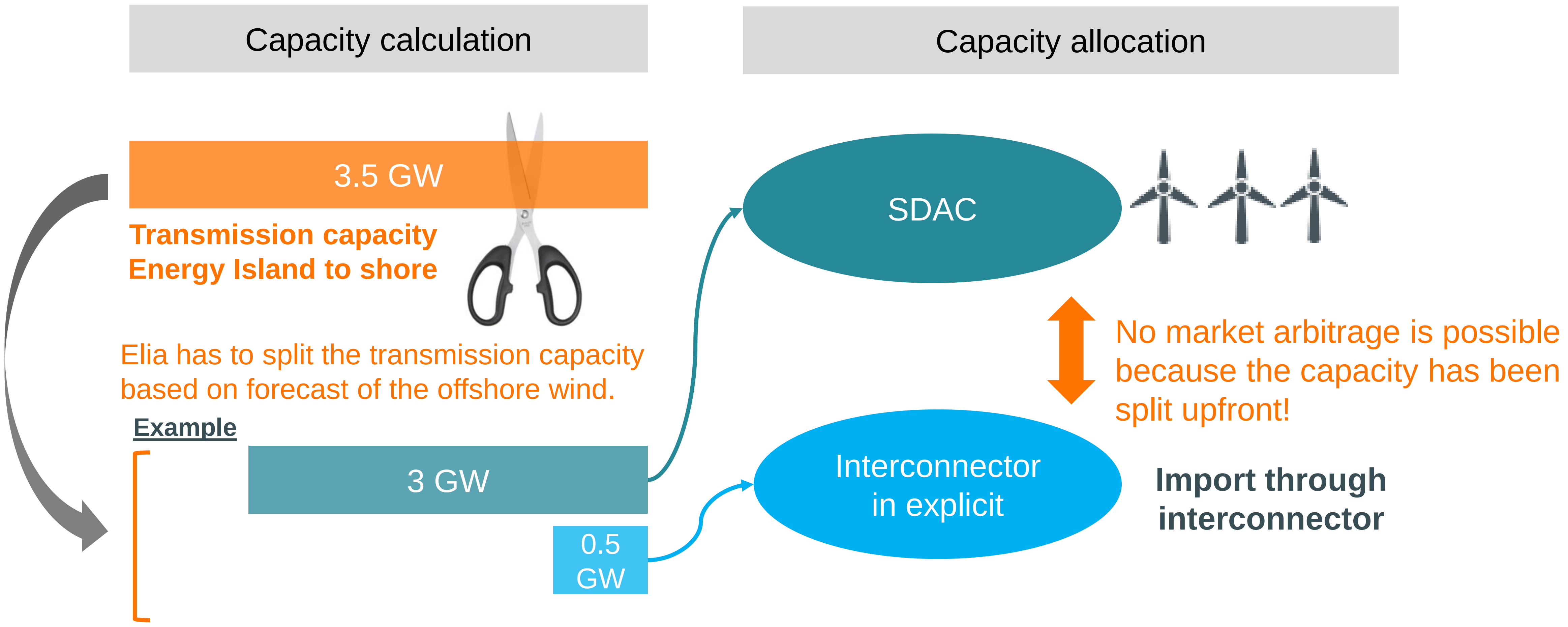
SDAC
welfare optimization

All other buy/sell bids

Example result of allocation: the 3.5 GW transmission capacity of the energy island is allocation for 2.5 GW to offshore wind and for 1 GW to import through the interconnector with UK



As long as we are in an explicit coupling context, there is no point in establishing an offshore bidding zone as it cannot realize its objective of efficient allocation



Explicit coupling does not fit with EU’s offshore ambition

- **Integrating 300 GW of offshore wind in a cost-efficient way requires** both:
  - An efficient planning of capacities ➔ hybrids and meshed offshore grids
  - An efficient use of the capacities

- **Explicit coupling however fosters a more complex approach and less efficient use of capacities:**
  - Market participants will make mistakes when forecasting prices
  - Economic arbitrage in a hybrid set-up is not possible. Instead, TSOs have to ex-ante split capacities based on forecasts, leading to:
    - Missed opportunities: too much wind forecasted ➔ too little capacity provided to the allocation
    - More system costs: too little wind forecasted ➔ too much capacity provided to the allocation ➔ redispatching

Explicit coupling is not scalable towards EU’s offshore ambition

Scenario's leading to implicit coupling and thus the application of an offshore bidding zone for MOG II

Key events	Timings
Nautilus	Earliest 2030
Return of UK to implicit price coupling	Unclear
Triton + DC circuit breaker	Estimated 2035

Scenario "EARLY": 2030

- Nautilus realized as planned
- UK returns to EU implicit price coupling by the time Nautilus is realised

Scenario "LATER": 2035

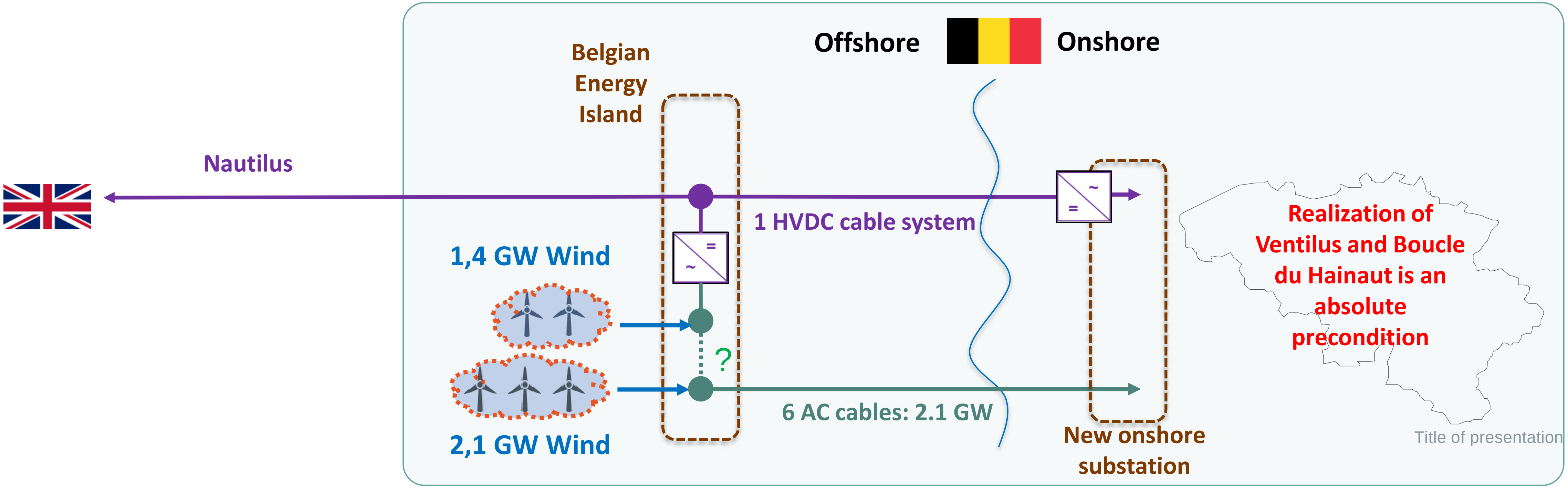
- No clarity on UK returning to EU implicit price coupling
- DC circuit breaker technology available, enabling to integrate Triton into MOG II on top of Nautilus

Working assumption: offshore bidding zone will emerge in the period 2030-2035

2. What is driving the scope of an OBZ

Scope of OBZ: which part of the 3.5 GW wind connected to MOG II will end up in the offshore bidding zone?

This depends on the feasibility to operate the DC and AC part of the MOG II grid as 1-node.



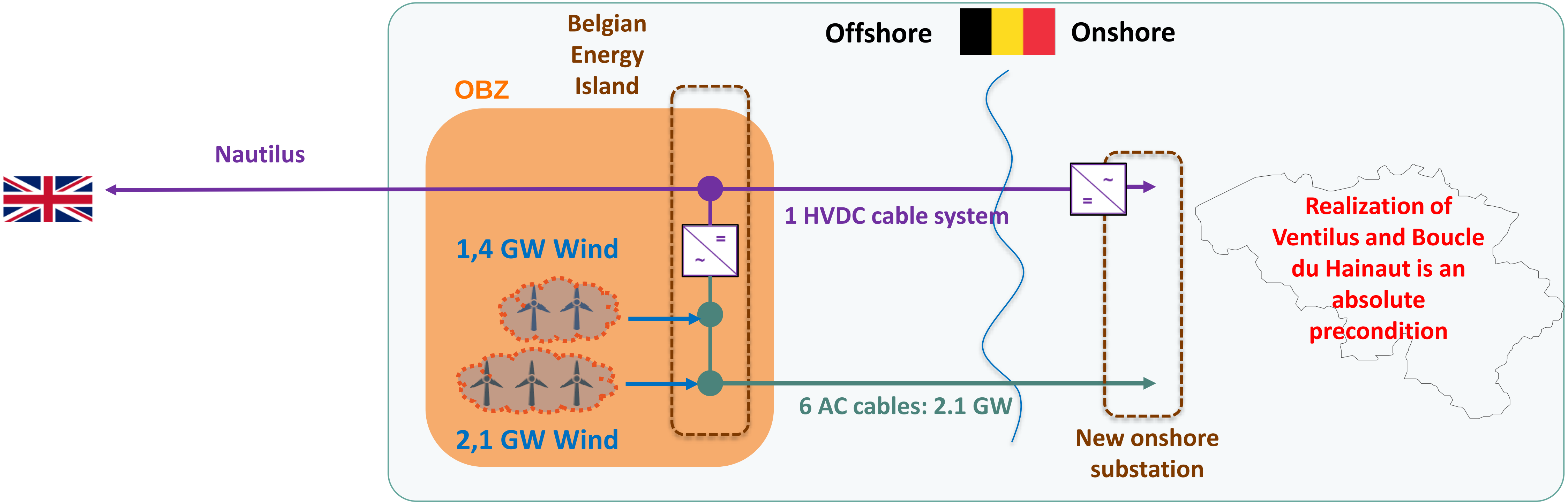
For simplification purpose the explanation on scope is applied to the scenario “early” thus illustrated with only Nautilus in the scheme.

Scope of OBZ: ambition = 1-node operation

Result: the full 3.5 GW wind is part of the OBZ.

Does this imply a temporary period where the wind connected prior the arrival of Nautilus is in home-market until Nautilus arrives?

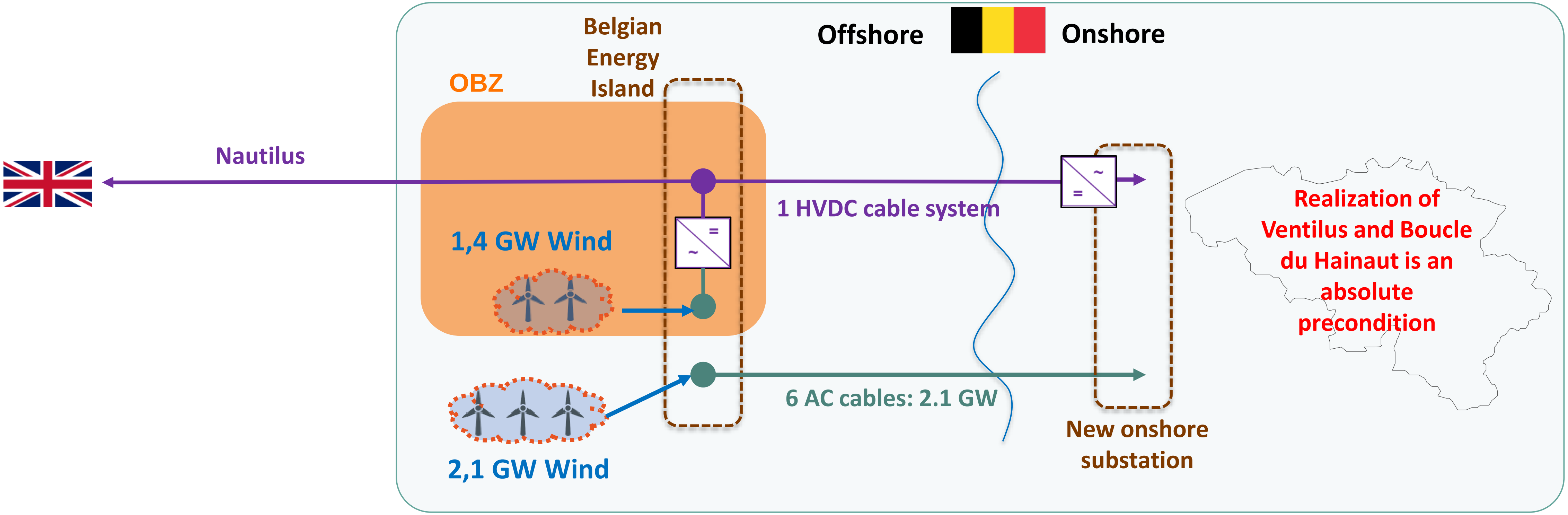
- If at that moment there is no certainty that the drivers to create an OBZ are met: YES
- If at that moment there is certainty that the drivers to create an OBZ are met: implementation choice



Scope of OBZ: situation under 2-node operation

Result:
- **The 1.4 GW wind connected to the DC node is part of the OBZ.**
- **The 2.1 GW wind connected to the AC node is in home market.**

Exception: for a long duration outage of the HVDC or of one of the AC cables, it could make sense to switch part of the production from one side to the other. This would have also an impact on the market setup for those parties. This is to be further analyzed.



3. Ideal target model to foster EU's offshore ambition

North Seas Energy Cooperation and UK establish cooperation framework to facilitate the development of offshore renewable energy

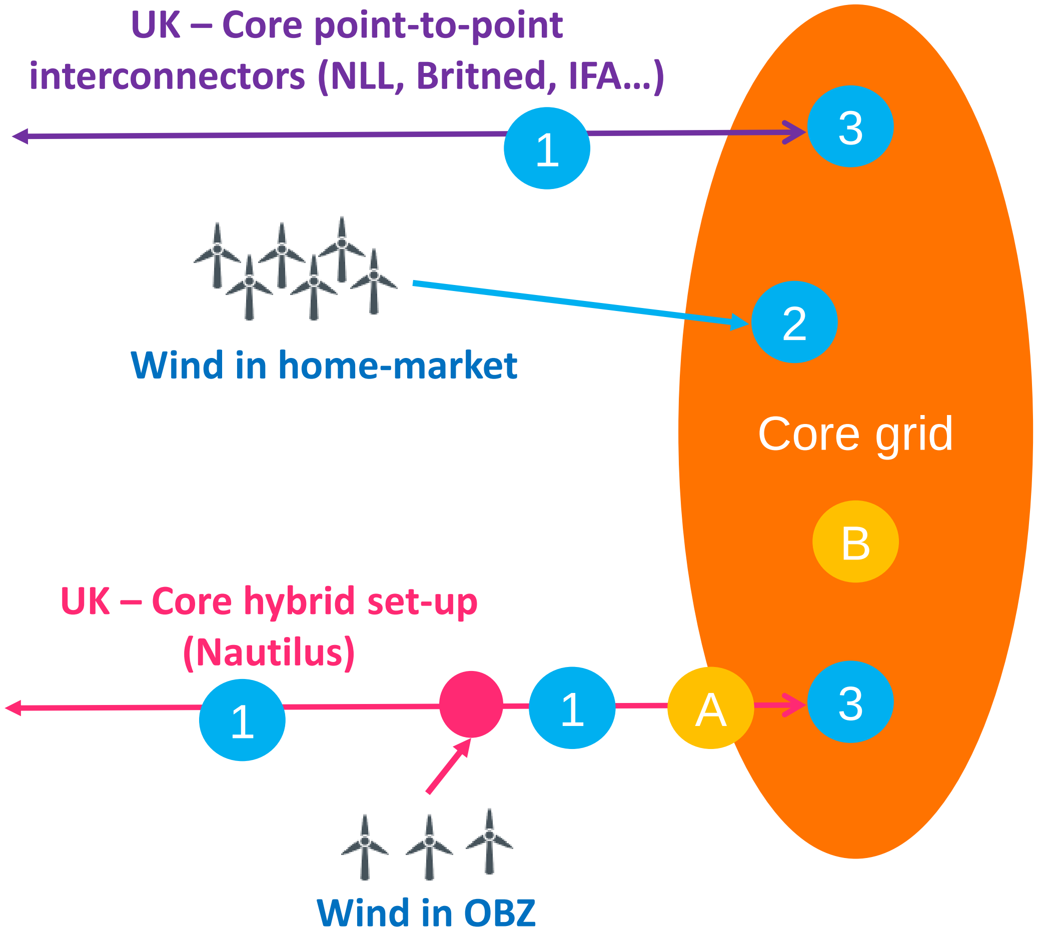
Dec 18, 2022

Through this MoU, the EU and UK aim to strengthen their joint action on offshore renewable energy and put in place a framework of cooperation following Brexit. The MoU specifies that the cooperation covers technical and expert dialogue, information exchange and sharing of best practices. The MoU provides a framework that is distinct yet complementary to NSEC's own work. The Commission and the NSEC member state acting as Co-Presidency will now work on the implementation of this MoU.

Welcoming the signature of the MoU, Commissioner Simson said:

> *"The Memorandum signed today provides the NSEC members and the UK with a basis to cooperate on offshore energy. Given the significant potential of offshore renewable energy in the North Seas, this cooperation is important to help achieve our joint renewable offshore ambitions. The exchanges will build on the successful work of NSEC to deliver concrete outputs."*

What is the most efficient market model: implicit capacity allocation, with OBZ and Advanced Hybrid Coupling



Capacity calculation

1. Capacity of the DC interconnections is provided to the market
2. Core: wind in home-market gets priority access to Core grid through best forecast – *TSO responsibility*
3. Core: calculate how much capacity of the Core grid can be made available, jointly for Core interconnectors + UK interconnectors + offshore wind in OBZ

Capacity allocation

A. **OBZ:** allows competition between wind in OBZ & flows from/to UK for the capacity of the DC link between OBZ and BE

B. **Advanced Hybrid Coupling:** Implicit market coupling between, which will be applied in Core as target model.

Advanced Hybrid Coupling is seen as the EU target model. It is from a welfare point of view the most efficient way for the implicit market coupling between regions. Therefore it is important to understand how it works and how it impacts the formation of the price in the OBZ.

What is Advanced Hybrid Coupling? (1/3)

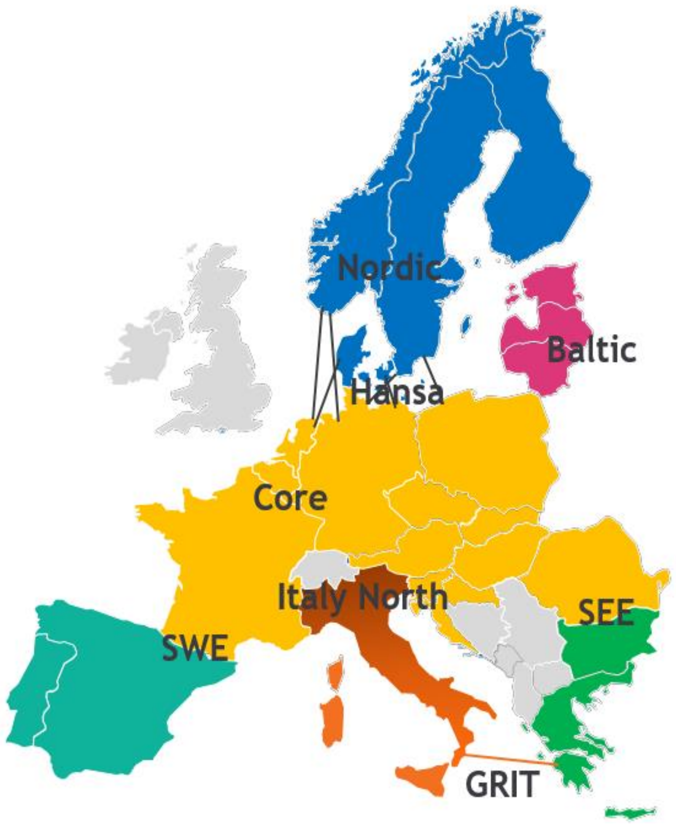
Each Capacity Calculation Region (CCR) is responsible for calculating the cross-zonal capacity for the bidding zone borders assigned to the CCR. The resulting capacities are submitted as “constraints” to the market coupling algorithm, together with a mathematical representation of *“how much capacity of each grid element would be used by each border of the CCR if the market coupling algorithm assigns an exchange to the border“*.

Exchanges on bidding zone borders external to the CCR also create flows in the CCR’s grid. For example, the bidding zone border between Norway and the Netherlands is assigned to CCR Hansa yet any market exchange through this border will not only use the capacity of the NorNed HVDC interconnector, but will also capacity of grid elements in CCR Nordic and CCR Core.

There are two ways to take into how capacity of grid elements in a CCR is used by external borders:

- **Standard Hybrid Coupling (SHC)**: exchanges on the external border are forecasted during the capacity calculation step – **currently implemented in Core**
- **Advanced Hybrid Coupling (AHC):** no forecast needed anymore. The effect of an exchange over the external border is mathematically calculated and used as input for the welfare optimization of the implicit market coupling - **implementation is expected in the coming years in the Core, Nordic and Hansa CCRs**

Current configuration of CCRs



Note: the technical concept of AHC can also be applied to HVDC borders inside the same CCR. This is called evolved flow-based (EFB). This solution is already applied today on the ALEGrO interconnector between BE and DE

What is Advanced Hybrid Coupling? (2/3)

Approach in Standard Hybrid Coupling (SHC):

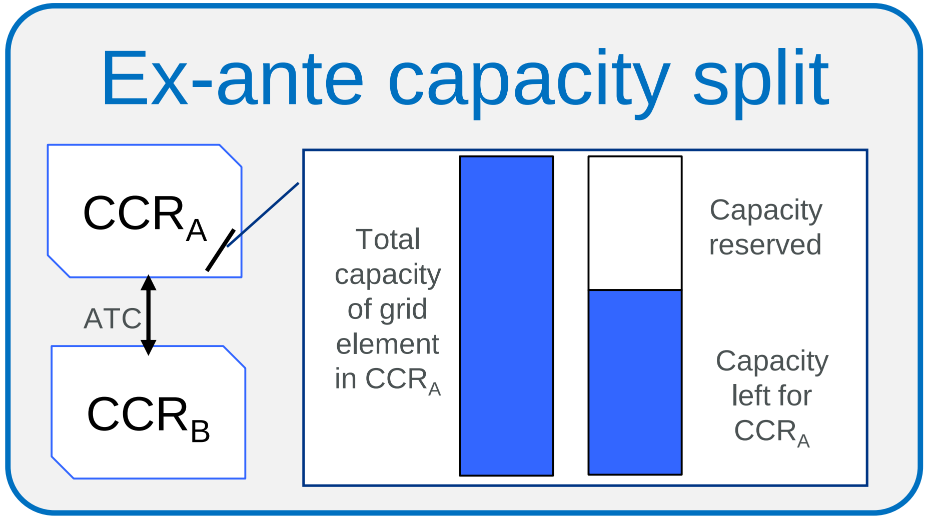
Step 1: what is done in the capacity calculation?

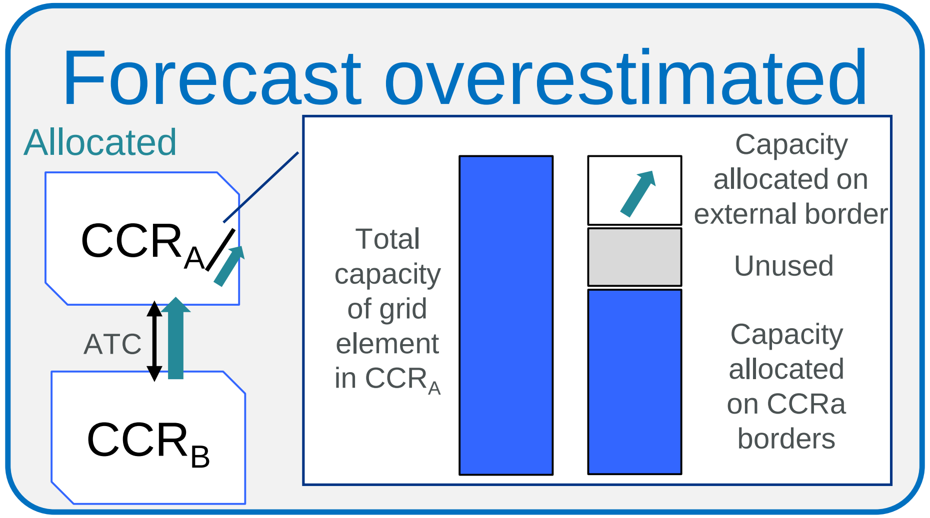
- The exchange over the external border is forecasted.
- The impact of this forecast is seen as a fixed feed-in/feed-out, thus the capacity of a grid element is ex-ante split between how much is used by external borders and how much is available for the bidding zone borders inside the CCR.

Step 2: what is done in the capacity allocation?

- In the market coupling the exchange across the external border is a parameter which can vary between 0 and 100% of the available transfer capacity (ATC) of the border.
- This means that the allocated amount of exchange can be different from what was forecasted…which brings inefficiencies:
  - Forecast < allocated (Underestimation) :
    - Risk of overloading of the grid elements which may require redispatching
  - Forecast > allocated (Overestimation):
    - Unused capacity (causing welfare losses) might remain

These inefficiencies of Standard Hybrid Coupling are not ideal, which is why the target model is Advanced Hybrid Coupling

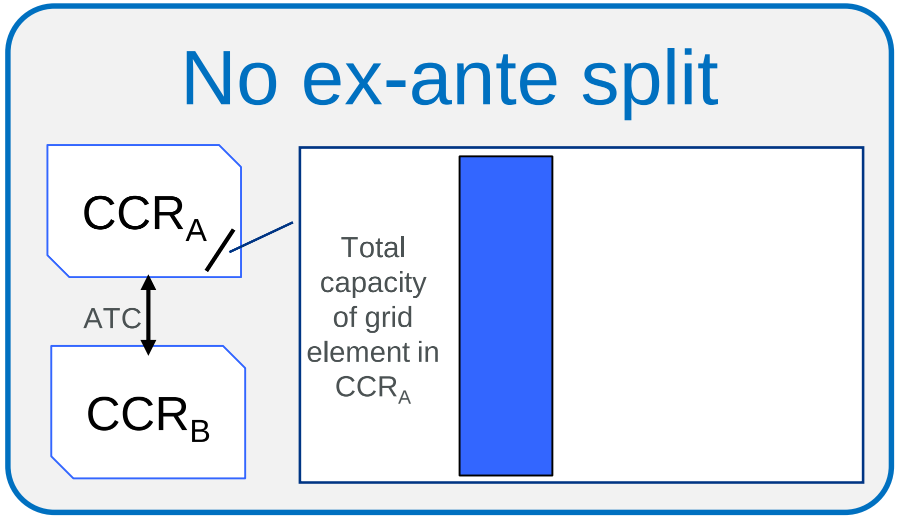




What is Advanced Hybrid Coupling? (3/3)

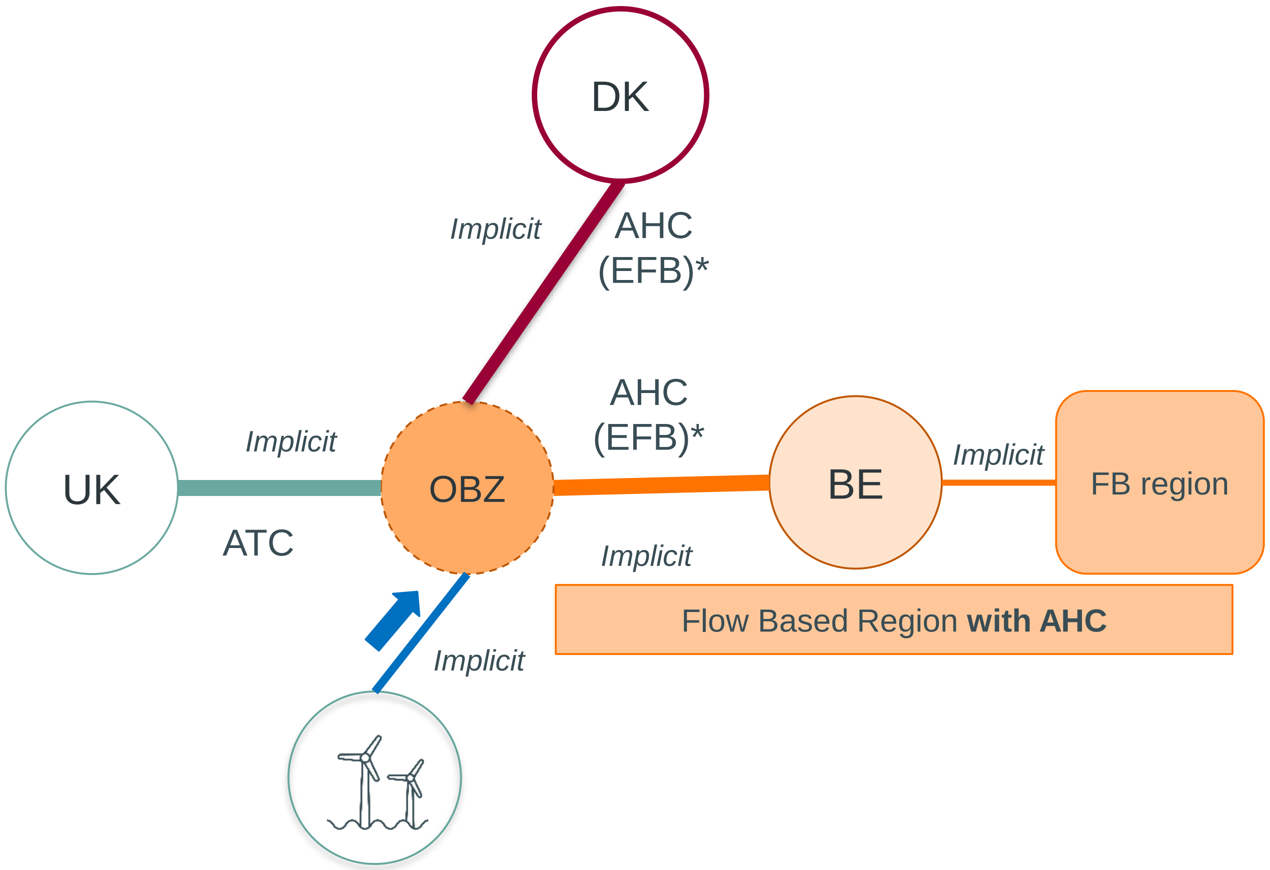
Approach in Advanced Hybrid Coupling:

- There is no need to make an ex-ante split of the capacity based on forecasts.
- In addition, the capacity calculation step now also includes the mathematical representation of how much capacity of each grid element is used by market exchanges over the external borders with AHC.
- The available capacity of each grid element is offered directly to the market coupling, together with the mathematical representation of "how much capacity of each grid element is used by each border".
- The market coupling has now all information to decide how to allocate the available capacity most efficiently across all borders in order to maximize the welfare.



Application of the target model on MOG

Target model assumed:
- Implicit market coupling with UK
- Advanced Hybrid Coupling (to UK and to Denmark)
- DC breaker technology available (Triton is connected to MOG II)



There are two set-ups possible for the application of AHC

Set-up A: 1-sided Advanced Hybrid coupling:
- AHC is applied on the BE side of the OBZ
- The connection to the other bidding zone remains in ATC. This is likely the set-up when UK returns to implicit market coupling

Set-up B: 2-sided Advanced Hybrid coupling:
- AHC is applied on the BE side of the OBZ
- AHC is also applied on the connection to the other bidding zone = likely set-up for DK interconnector

A mix can exist, for example where the interconnector from the OBZ to UK applies ATC (1-sided AHC) and the interconnector from OBZ to DK applies AHC (2-sided AHC).

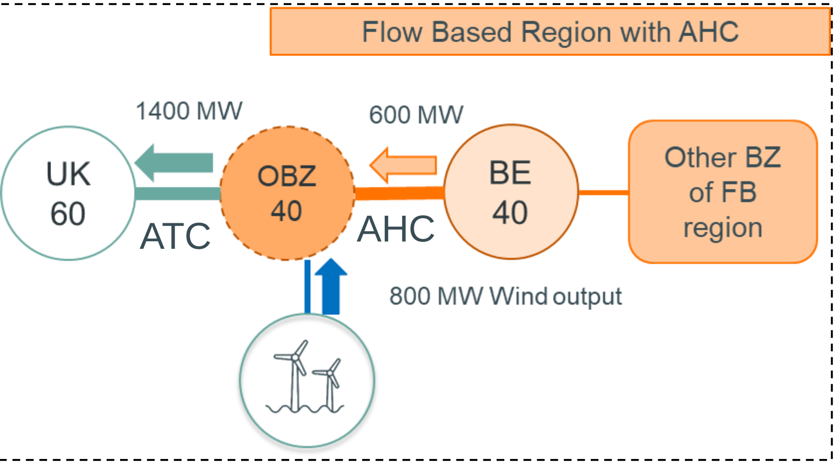
**AHC or EFB?: The bidding zone borders OBZ-DK and OBZ-BE have to be assigned to a CCR. If they are both assigned to CCR Core, these are internal borders for the CCR Core and the terminology evolved-flow-based (EFB) applies. The way how the algorithm performs the market coupling and the impact on price formation as explained in the following slides remain the same.*

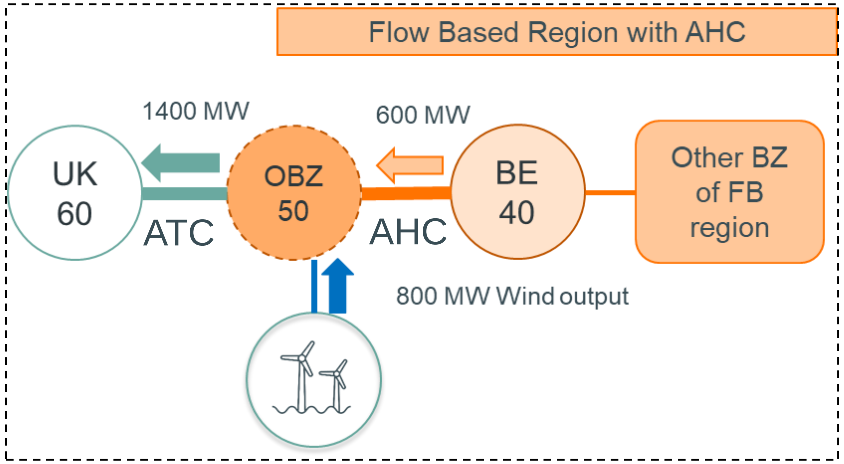
Effect of Advanced Hybrid coupling on price of the OBZ

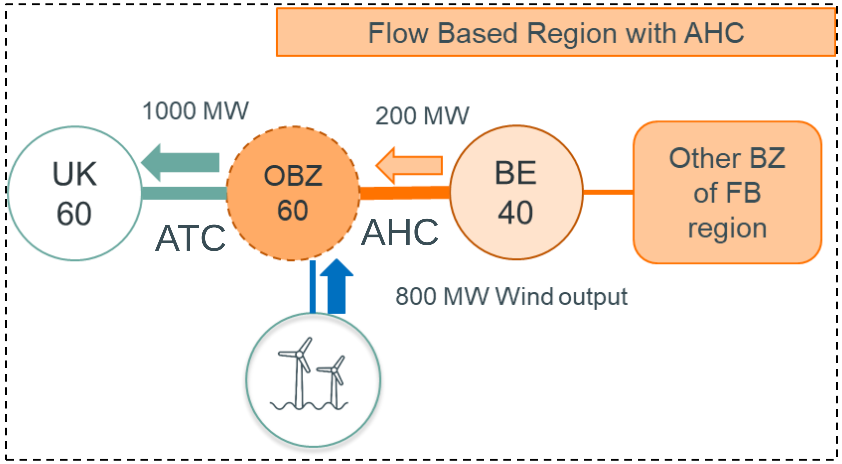
Set-up A: 1-sided AHC = likely set-up for Nautilus once UK returns to implicit

- Flow-based allocation: in case of congestion in the Core Flow-Based region, a price delta will occur between all bidding zones of the Core region. This also applies to the OBZ.
- The price of the OBZ can be:
  - The same as the price of the BE bidding zone. When? If there is no congestion in the FB region ➔ all FB bidding zones see the same price
  - Different from the BE & UK bidding zone price. When? If the congestion in the FB region does not limit the flow on the interconnector between OBZ & UK.
  - The same as the price of the UK bidding zone. When? If the congestion in the FB region limits the flow on the interconnector between OBZ & UK.

No congestion in FB region ➔ Price OBZ = same as BE, different from UK	Congestion in FB region, flow OBZ-UK not limited ➔ Price OBZ differs from UK and BE	Congestion in FB region, limitation of flow OBZ-UK ➔ Price OBZ different form BE, same as UK







Note: for the purpose of this example, it is assumed that only 800 MW wind output from MOG II was expected and offered to the Day-Ahead market coupling

Set-up B: 2-sided AHC = likely set-up for Triton

- In such a situation, it might occur that the price of the OBZ is also higher OR lower than the price of both onshore hubs.

4. Legal framework to define OBZ

Legal framework to review a bidding zone configuration

Commission Regulation (EU) 2015/1222 (CACM) of 24 July 2015 sets out detailed guidelines on cross-zonal capacity allocation and congestion management in the day-ahead and intraday markets. Articles 32 and 34 of the CACM set out rules on review of bidding zone configuration.

➔ full bidding zone review process = heavy process taking 2-3 years to come to a decision to review the bidding zone configuration

Commission Regulation (EU) 2019/943 (CEP Regulation) of 5 June 2019 on the internal market for electricity offers the possibility to follow CEP Article 14 instead of CACM

➔ offers an alternative way to decide on a review of the bidding zone configuration without having to apply the full bidding zone review process

A national approach with relative short lead times is possible

- **Step 1:** Elia writes a structural congestion report. Content of the report is not pre-determined. Elia's preliminary view:
  - Explain the anticipated structural congestion by referring to the hybrid grid design approved in most recent national development plan. Explaining the triggers, the status of implementation of those triggers, etc.
  - Introduce OBZ and the conditions to be met for the OBZ to be an efficient solution to manage the structural congestion.
  - Justify introduction of OBZ has a negligible impact on the neighboring TSOs ➔ decision can be made by Belgium alone
- **Step 2**: CREG approves the structural congestion report. This comes along with a **public consultation** as per national rules. Anticipate this takes **3 months**.
- **Step 3:** Elia and CREG notify the neighboring transmission system operators that, on basis of the approved structural congestion report, Belgium initiates a review of its bidding zone configuration.
- **Step 4: Belgium as Member State has 6 months** to **consult the relevant stakeholders**, take a **reasoned decision** on the creation of an OBZ and notify this to ACER & EC. The decision should mention an **implementation date.**
  - Relevant stakeholders
    - CEP regulation Art 14(7) states other Member States may submit comments
    - CEP is not explicit on why are the relevant stakeholders and hence if a public consultation is required. When we more concretely prepare this process, it is to be assessed if the public consultation organized by CREG in step 2 is sufficient.
  - Reasoned decision: content is build up in previous steps. Best practice to wrap-up comments received (if any) from relevant stakeholders and how these have been taken account of.
  - Implementation date: hints that the decision can be made sufficiently firm
- **Step 5:** Publication of the decision

Approach to integrate OBZ in the MOG II planning

2-3 years

Step 0

Pre-consultation on OBZ

(timing to be defined)

Elia continues to create awareness and engage with stakeholders

The objective is to do a **consultation on the role of OBZ, the conditions that trigger it and balancing aspects**. Timing to be defined.

Step 1

Formal process to create OBZ

The conditions to have sufficient certainty on scope and timing are monitored.

Uncertainties on scope / timing of the OBZ are likely to exist at the moment of first tender and hence the launch of the formal process is anticipated to take place thereafter.

Step 2

Implement the OBZ

The new bidding zone borders need to be formally assigned to a capacity calculation region. This requires an amendment to the pan-EU methodology of CCR determination.

The new bidding zone borders need to be integrated into the capacity calculation and allocation processes.

With a lead time of 2-3 years, the formal process to create the OBZ can be initiated when there is a firm decision on the implementation of the drivers of the OBZ

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5. Annex: list of received questions and our answers on topics "Market design" and "OBZ process"

Questions Market design	Answers
Regarding AC or DC connection for offshore generation, does it have an impact on the OBZ of HM choice?	Tackled in today’s presentation
What would be the governance of such a OBZ - role of TSO, of regulator?	This is prescribed by European legislation • At one side there is the legal process to establish an OBZ • On the other side there are the requirements stemming from CEP, CACM, FCA, SOGL, EGBL that have both o A pan-EU dimension, for example integration into balancing platforms and allocations o A regional dimension as each bidding zone border has to be assigned to a capacity calculation region (CCR) that governs capacity calculation and operational security analysis processes. In addition, there are also SORs (system operation regions) to coordinate some of the activities for which RCCs (regional cooperation centers) are responsible on a level at least as large as the CCR.
What are the implications of changes in the allocation process for the Nautilus interconnector with the UK (explicit/implicit/advanced hybrid coupling), and is the planning for these changes compatible with the timeline of the offshore wind auction in Belgium?	Tackled in today’s presentation
What are the detailed implications and pro’s and con’s of alternative regulatory solutions, as f.i. deviation and/or derogations to the EU framework? A full mapping and detailed comparison is deemed appropriate.	Exemptions and derogations from 70% regulation do not offer a proper (market-based) solution to manage the structural congestion.
What is the long-term perspective of the evolution of the proposed offshore bidding zone and related interconnectors/export capacity? Will the Belgian nodal offshore bidding zone in the future merge with other offshore bidding zones to create a large zonal bidding zone? This long-term view is essential for the offshore wind developers to be able to develop their view on price and volume expectations in order to prepare their bids;	The purpose of the OBZ is to manage structural congestion efficiently, so we expect OBZs to emerge on a case-by-case basis where a hybrid set-up is being implemented.

Questions Market design	Answers
What is the market arrangement for the period starting with the first operational wind farm in the PE zone and ending with the realization of the Nautilus interconnection with UK? In this period without interconnector, will a Home Market arrangement be put in place?	Tackled in today’s presentation
What in case the Nautilus project experience delays, will there be any liability arrangement be put in place?	Please elaborate your question
Can you provide an overview of the DA prices in the UK for the last [2-3] years and the occurrence of negative prices, in comparison to BE DA prices?	Link to public available information through ACER : Microsoft Power BI
Does a NEMO (Epex, Nordpool,…) need to open a new market for the OBZ (DA and ID)? If yes, has this been discussed with the Nemo’s? Is the timing towards implementation compatible?	Tackled in today’s presentation: the OBZ will indeed have to be integrated into the SDAC/SIDC systems, and such implementation track is to be started up when the formal process to decide on OBZ is started.
Elia TF MOG2 1 April 2022: “Our goal is to create visibility on the market integration and grid design scenarios, whilst acknowledging these are inherently subject to legal/political context. This visibility should help the assessment of volume risk by parties bidding into the tender.”	Tackled in today’s presentation
According to Elia, when a hybrid interconnector is built, the use of an OBZ is better than the ‘home market approach’ to optimise the use of the limited grid capacity. Can Elia share the calculations which demonstrates that the OBZ market design in the specific case of the PEZ provides additional social welfare for the Belgian society compared to the home market design? The conclusions of large-scale theoretical and generalized assessments demonstrating the merits of OBZ on social welfare may not apply to a bidding zone located this close to its home market.	Under a home market design the transmission capacity between Energy Island and coast will have to be ex-ante split during the capacity calculation process in D-2 based on forecasts. Forecasts come along with forecast errors, leading to situations where: - Forecast of offshore wind is underestimated => redispatch needed - Forecast of offshore wind is overestimated => underutilisation of the capacity thus welfare loss

Questions Market design	Answers
Can you explain the difference between re-dispatching costs and congestion rents, and how they are dealt with in Elia? Are they passed-through via the tariffs (i.e. redispatch costs leading to higher tariffs and congestion rents leading to lower tariffs)? Do both redispatching costs and congestion rents incentive the TSO to invest in grid-capacity?	**Redispatch** Redispatch is a corrective action taken after the market coupling to keep the grid secure. The process of redispatch and the sharing of its associated costs is for Elia's grid (being part of CCR Core) subject to the respective Core methodologies. Redispatch costs are pass through to the tariffs, whilst at the same time Elia is being incentivized to keep these costs low. Investing in the grid is driven by a TOTEX approach. So indeed, an increasing level of redispatch cost (OPEX) leads in a natural way to look at grid investments (CAPEX) to alleviate the congestion. **Congestion rent** Congestion rents are a direct result of allocations. Allocations exist already for yearly, monthly and daily timeframes and are being implement for the intraday timeframe. The use of congestion rents is regulated (2019/943 regulation Article 19) and is to be used for: A) guaranteeing the actual availability of the allocated capacity including firmness compensation. B) maintaining or increasing cross-zonal capacities through optimisation of the usage of existing interconnectors by means of coordinated remedial actions, where applicable, or covering costs resulting from network investments that are relevant to reduce interconnector congestion. The congestion rent is thus to be used to pay for redispatch, to pay out the long-term transmission rights and to invest in the grid.

Questions OBZ process	Actions/Answers
What are the legislative changes required to introduce an OBZ for the PE zone (at BE and EU level)?	Tackled in today's presentation
What is the process and timeline to define the regulatory framework for the introduction of an OBZ for the PE zone, both at a national and at and EU level?	Tackled in today's presentation
Who finally decides whether or not an OBZ will be installed? If this is the Minister of Energy, have discussions with the Cabinet been started? Are they been involved?	Tackled in today's presentation. Yes, they have been involved.
What is the planning of Elia to implement these changes and how does it match with the planning of the offshore wind auction, without introducing additional delays?	Tackled in today's presentation
Has the UK or National Grid formally approved the concept of the OBZ? Should they? By when? What if they don't?	No
When the OBZ has evolved and multiple interconnectors have been installed between other countries, will the OBZ still be governed by Elia or governed/transferred by/to a new entity at EU level (offshore TSO?)?	The purpose of the OBZ is to manage structural congestion efficiently, so we expect OBZs to emerge on a case-by-case basis where a hybrid set-up is being implemented.

Thank you.