Hybrid Offshore Project

Market Arrangements

A Eurelectric discussion paper

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WG Market Integration & Network Codes

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Executive Summary

The European Commission (EC) has come up with an ambitious EU offshore strategy[1] with the goal of 300 GW of offshore capacity by 2050 (and 60 GW by 2030). Several Member States have also included objectives on offshore generation in their respective National Energy and Climate Plans. The EC also states that an offshore grid will be needed to support this important target. This grid will ideally be built around hybrid projects - which combine offshore generation and transmission elements - in cases where they can reduce costs and the use of maritime space. At the same time, the EC acknowledges that a significant proportion of offshore projects is likely to continue to be developed under a radial structure.

The EC recognizes that hybrid projects are currently being set up without a certain regulatory framework and that questions about the distribution of costs and benefits among project stakeholders need to be solved. **Eurelectric acknowledges the future role of offshore renewable energy projects** in the decarbonisation of the EU's energy system, especially under a hybrid structure. Eurelectric takes note of the **challenges ahead and sees the opportunity to analyse market arrangements** in light of each solution's efficiency of market dispatch, quality of price signals, and robustness and stability requirements. This paper analyses the EC's proposals in depth and will qualify and assess the functioning of the various options. One main finding has been that it is a complex subject which requires more detailed discussion and consultation with all relevant stakeholders.

The efficiency of the power system at the regional level relies on the proper integration of offshore hybrid projects into electricity markets, notably by belonging to a Bidding Zone (BZ). Considering this point, **Eurelectric analyses the three main possibilities for offshore hybrid projects** in terms of electricity market arrangements: the Home Market (HM) under two of its variants (HM-EXEM and HM-COMP) and the Offshore Bidding Zone (OBZ) setups. This discussion paper identifies the challenges and feasibility of each setup **with the potential that they could co-exist in the future:**

- The **HM-COMP** setup comes with offshore generation (OG) assets belonging to an onshore bidding zone, it has unconstrained access to this bidding zone **and** redispatching and countertrading measures in place to comply ("COMP") with the

[1] Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions: An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future COM/2020/741 final

minimum threshold (70 % of the interconnector capacity to be made available for cross-border trade) set under Art 16.8 of the EU Electricity Regulation (E-Reg)[2].

- The **HM-EXEM** setup comes with offshore generation assets belonging to an onshore bidding zone, it has unconstrained access to this bidding zone **and** transmission capacities used for exporting the Offshore generated electricity to shore exempted ("EXEM") from the application of the minimum threshold requirement in the Art 16.8 of the E-Reg. Art 16.8 is still to be applied to the transmission capacity after deduction of the forecasted OG production.
- The **OBZ setup** comes with offshore generation assets belonging to their own offshore bidding zone **and** leaves transmission capacity allocation to the market coupling, in compliance with the minimum threshold set under Art 16.8 of the E-Reg.

In a nutshell, those setups are differentiated by the **compliance or not with Art 16.8** and by the **creation or not of an offshore bidding zone**. This last differentiation also determines the status of the transmission asset connecting offshore generation to shore which can be a multi-purpose interconnector spanning a bidding zone border or a Multi-purpose Internal Network Element (MINE).

The OBZ and HM-EXEM setups especially require amendments to the current regulation. At first glance, the HM-COMP setup does not, but Eurelectric believes it should also be included in further investigations for the best way forward, without prejudice, all three have benefits and drawbacks.

In the current state of play, **Eurelectric cannot express a clear preference in favour of one setup** (or even an order of preference). In the analysis summarized below, too many elements lack clarity and require a European policy debate. Therefore, Eurelectric has instead identified the challenges to be overcome should a specific setup be implemented. In any case, **Eurelectric strongly urges avoiding a trial-and-error approach** as it would undermine investments in offshore hybrid projects for non-regulated actors, increase the system costs, and have collateral effects on onshore assets. It is therefore **important to properly identify the pros and the cons of each market arrangement before any decision is taken**. However, to not delay investments in offshore hybrid projects, the legislative proposal should be on the table **as early as possible in 2022**. The combination of those two elements makes the offshore hybrid topic a **priority topic** to be tackled by the EC in the coming months.

Eurelectric is of the opinion that the HM and OBZ setups are not mutually exclusive and can co-exist in Europe. What is clear is that if neighbouring countries were to apply diverging market arrangements, i.e. one applying HM setup connected to another country with OBZ setup, it would add a level of complexity - but not to an unsurmountable level that would prevent this combination.

Home Market Setup (HM Setup)

The **HM-COMP** and **HM-EXEM** setups provide offshore generation with unconstrained access to the Home bidding zone at each market timeframe (forward, day-ahead, intraday and balancing). **The depth and liquidity of an onshore bidding zone's market provides (long-term) certainty about market revenue while decreasing the cost of market entry**

[2] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

and the risk premium associated with the production of power. This will, if the business case is positive considering all other revenue streams, incentivise merchant investments in offshore generation. The HM-COMP setup requires market correction actions by TSOs just after the Day-ahead timeframe given the application of the art 16.8 minimum threshold. Fictive capacity is made available for cross-border trades without considering offshore production that has priority access to this same capacity. This can potentially **have an impact on the accuracy of the energy price signal in Day-ahead as well as on the efficiency of the final dispatch** should remedial action coordination by TSOs not be fully fledged.

On top of that, both setups require after-market correction actions in the intraday and balancing timeframes because there would be situations where the transmission capacity will not be able to fully accommodate offshore generation and commercial trades. Negative prices situations are also touched upon, even if Eurelectric **expects that the regulatory framework should stem the causes of such events (e.g. inefficiently designed support schemes).** These can cause an inefficient dispatch as offshore generation is being pre-allocated transmission capacity whereas cheaper generation could have used it instead.

For the HM setups, Eurelectric also notes that forecast responsibilities, having an impact on the market, lie ultimately in TSOs' hands. It must be ensured that correct incentives and clear rules for sharing remedial actions are presented to optimise transmission asset capacities.

Offshore Bidding Zone Setup (OBZ Setup)

Under the **OBZ setup**, the Offshore generator must compete with energy bids located in other (onshore) bidding zones to access cross-border capacities. **This prevents potential inefficient dispatch situations**. It is shown that the Offshore generator in its bidding zone will get the day-ahead price of the low-price neighbouring onshore bidding zone, being coupled with the exporting side. Compared to HM setups, part of the welfare is captured by the interconnector owner in the form of congestion rent rather than being earned by the offshore generator. Moreover, any capacity restriction on the interconnectors linking the offshore bidding zone (OBZ) to a neighbouring bidding zone can lead to the impossibility of exporting all OBZ production, leading to low market-clearing prices in the OBZ (as low as zero given the marginal production cost of wind generation).

The financial incentives should be sufficiently clear and stable to develop (offshore) transmission and generation capacities. The financial interplay between offshore generator and transmission infrastructure developers must be considered since their respective revenue streams are interdependent. The potential need for adapting the respective revenue streams (e.g. through support or redistribution schemes), taking into account the dual use of the infrastructure, depends on the chosen market arrangement and also the physical configuration of the offshore hybrid project and future offshore grid developments. **Eurelectric supports the development of a legal framework that would facilitate such schemes if needed**.

In the balancing timeframe, Eurelectric notes that **a major task will be to monitor and maintain the balance at an offshore hub**. Any offshore generator production forecast error will have to be taken care of onshore because of the likely lack of balancing means within the offshore hub. The procurement and related dimensioning of balancing capacity will have to be duly considered, potentially with cross-border procurement and reservation of transmission capacity. **It must be ensured to tap the full potential of EU Balancing platforms**. Balancing Responsible Parties, onshore or offshore, have their imbalances eventually settled at the imbalance settlement price. Whereas it is already defined at the onshore bidding zone, it should also be defined under an OBZ setup, based, notably, on the balancing energy bids activated for maintaining the balance in the offshore hub.

Eurelectric would also like to broaden the discussions to topics not directly related to the above-mentioned market timeframes but that equally need clarity, especially in terms of governance and evolutions of the market environment.

Eurelectric notes that the Bidding Zone Review process can play a role in the determination (and potential evolution) of the market arrangements that will be applied for offshore hybrid projects. However, offshore investment is a long-term activity (20 years and more), while the timeframe of the Bidding Zone review is rather short-term with tenders of three years and mainly revolves around existing structural congestions. **This prevents the Bidding Zone Review, in its current setup, from playing an instrumental role in the determination and evolution of bidding zones delineation around offshore hybrid projects**. In any case, Eurelectric wants to reiterate the **need for Bidding Zone delineation stability** given its impact on the market revenues of, notably, offshore generation and transmission assets but also onshore market participants.

The **coordination and cooperation of all stakeholders** (possibly with third countries) must be ensured via existing or future coordination bodies. The development of offshore hybrid projects including the sizing of transmission network infrastructure, the sharing of associated costs, and the possibility of anticipatory grid investments, should be discussed promptly and integrate the TYNDPs as already suggested by the EC.

Moreover, the **possible ownership structures and operation of transmission infrastructure** should be tackled considering merchant, exempted, or regulated ownership, possibly all active in the same offshore hybrid project (composed of different transmission assets).

Eurelectric also identifies challenges related to the **interplay between the tendency of harmonisation on the EU level and the need to maintain national energy policy goals and particularities** (e.g. tariffs set at the national level).

In conclusion, the fact that Eurelectric cannot express a preference regarding market arrangements is the sign that **large areas of this subject are still immature, preventing any informed position statement.** This discussion paper rather aims at identifying those areas and presenting possible solutions to feed the discussion with an industry view. **Eurelectric calls EU legislators to further engage with stakeholders to detail grey areas identified in this discussion paper via a European debate, participation in which Eurelectric stresses its deep interest**.

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A. Introduction

Offshore renewable energy can play a major role to enable Europe to become the first climate-neutral continent by 2050. In this context, the European Commission (EC) has come up with its ambitious EU offshore strategy[3] with a goal of 300 GW offshore wind capacity by the end of 2050 within the EU's Member State territory. Several Member States (MS) have also included objectives on offshore generation (OG) in their respective National Energy and Climate Plans. Moreover, in the recent proposal of the revision of the TEN-E regulation[4], one of the specific objectives mentioned is to have at least 10 projects of common interest (PCIs) to support the deployment of offshore grids for renewable energy by 2026. The EC recognizes the importance of enabling the cross-border cooperation that is required to deploy the levels of offshore renewable energy needed. Specifically, EC identifies that offshore electricity generation would progress more efficiently, with significant welfare gains, if it is developed in the framework of offshore hybrid projects[5], which combine OG and interconnector. At the same time, EC acknowledges that a significant proportion of offshore projects is likely to continue to be developed under a radial structure which has been the traditional practice. According to the EC, hybrid projects can yield cost savings of up to 10 %[6].

Although EC identifies some cost savings resulting from establishing offshore hybrid projects, it recognizes that these projects are currently facing risks due to legal uncertainties related to regulatory treatment and other issues such as the distribution of costs and benefits among project stakeholders. While Eurelectric acknowledges the future role of offshore hybrid projects in the decarbonization of the EU's energy system, we take note of the challenges ahead and see the opportunity to analyse the market arrangements to be put in place for new offshore infrastructure[7]. We also take note that MSs' ambitions to develop offshore hybrid projects already by 2030 (tendered within the next 2 years) are at risk if legal and regulatory uncertainties are not resolved[8].

Furthermore, Eurelectric would like to remind EC about several criteria and aspects to be considered while establishing the market arrangements for new offshore hybrid projects. According to the Energy Governance Regulation[9] Article 4.d.1 and Annex I, an investment in interconnector (IC) should always benefit the Socio-Economic Welfare (SEW) and present a positive cost-benefit analysis (CBA). On top of that, due to the project's nature, market arrangements must ensure efficient price signals. This will allow merchant investments (be it exempted/merchant interconnectors[10] or generation assets exposed to market prices)

[3] Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions: An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future COM/2020/741 final

[4] Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure, OJ L 115, 25.4.2013, p. 39–75

[5] See section B. Definitions

[6] Roland Berger GmbH (2019), Hybrid projects: How to reduce costs and space of offshore developments, North Seas Offshore energy Clusters study

[7] In this context, we have already identified some existing initiatives aiming at addressing these challenges: Baltic Offshore Grid Initiative, North Sea Wind Power Hub Program, bilateral initiatives between National Grid Ventures and TenneT, or between Belgium and Denmark.

[8] These include Denmark, Belgium, Germany, the Netherlands, Estonia, Latvia, as well as third countries (U.K.).

[9] Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action, OJ L 328, 21.12.2018, p. 1–77

[10] for regulated developers, the requirement for efficient price signals is not relevant, since they can recover their costs through the tariffs, and their interconnection projects are usually subject to an approval by the NRAs which takes into account not only their market value (i.e. the congestion rent they generate) but also their impact on other components of the SEW (consumer and producer surplus).

contributing to an increase of SEW, to be financially viable, so that they can materialize. It is noticeable that a hybrid transmission infrastructure may involve several parties in terms of planning, investment, development and operation. The financial interplay between OG and transmission infrastructure developers also has to be considered since their respective revenue streams are interdependent. In any case, they should be supported by efficient market arrangements. Market arrangements must be optimised as far as possible to ensure an efficient dispatch and allocate the risks to the parties that can effectively mitigate them. Given the volumes at stake, well-designed market arrangements at all timeframes are of utmost importance to allow a swift integration of offshore hybrid projects to the electricity markets. Also, a stable market arrangement is required to ensure trust in the market functioning and reliable investment signals. Eurelectric urges to avoid a trial-and-error approach as it would undermine any inclination to invest in offshore hybrid project for non-regulated actors.

Due to the dual-use nature of the infrastructure, there will be periods where both OG and cross-zonal flows cannot be fully accommodated by the transmission infrastructure. The efficiency of the power system at the regional level relies then on proper integration of offshore hybrid projects into the electricity markets and proper access to trading and hedging products in all market timeframes. As all market timeframes are based on the concept of Bidding Zones (BZ), this is needless to say that OG must be included in a BZ with access to the following market timeframes and corresponding market coupling projects and products. The question is then: which BZ?

- Forward timeframe and the use of Financial Transmission Rights (FTR) according to the Forward Capacity Allocation Guidelines (FCA GL);
- Day Ahead (DA) timeframe and the Day ahead Market Coupling (DAMC) according to the Capacity Allocation and Congestion Management (CACM GL);
- Intraday (ID) timeframe and the continuous (+ auctions in 2023) Intraday Market Coupling (ID MC) according to the CACM GL;
- Balancing (BAL) timeframe and the role of Balance Responsible Parties (BRP) and Balancing Service Provider (BSP) within their Bidding Zone (BZ) or Load-Frequency Control area (LFC area) or across BZ through the EU balancing platforms according to the Electricity Balancing (EBGL) guidelines.

The market arrangements applied to offshore hybrid project depend on the definition of the Bidding Zone to which the OG belongs. Eurelectric notes that the Bidding Zone review process can play a role in the determination of market arrangements. Eurelectric would like to remind its views[11] on this process. The interdependency of Bidding Zone reviews and offshore hybrid projects should be duly considered. Eurelectric, therefore, emphasizes that the elements covered under the present discussion paper should also be considered under the Bidding Zone review process.

Eurelectric would like to discuss the two main possibilities in terms of market arrangements: the so-called Home Market (HM) under two of its variants and the Offshore Bidding Zone (OBZ) setup[12].

The goal of this paper is to analyse the challenges and workability of both setups with the potentiality that both could co-exist in the future.

[12] Other options that have been proposed in some studies or working papers, such as floating bidding zones, are not considered here, since they do not meet the minimal compatibility criteria with the current European market framework, in Eurelectric's view (*cf. supra*)

B. Definitions

In the framework of the offshore hybrid project, the following concepts are described in the **EU Electricity Regulation (E-Reg)**[13], however not always under the form of definition but rather as recital:

- **Interconnector**[14] means a transmission network element that crosses or spans a border between the Member States and which connects the national transmission systems of the Member States.
- **Offshore Hybrid Asset**[15] is an offshore electricity infrastructure with dual functionality combining the transport of offshore wind energy to shore and the support for cross-zonal exchanges.

In order to align on the definitions in the specific context of this paper, Eurelectric proposes the following definitions and adaptations:

- In the context of this paper, Eurelectric would like to extend the definition of **interconnector** as defined in the E-Regulation to transmission network element **which crosses or spans a BZ border**. This is because, in the context of the OBZ setup, the transmission network element might not cross an MS border, effectively. However, Eurelectric also notes that the definition of interconnector in the E-Dir Art 2(39) is broader ("equipment to link electricity systems") and would be applicable as such in the OBZ setup.
- **Multipurpose Internal Network Element (MINE)** is the transmission network element comprised within a bidding zone than with dual functionality combining the transport of OG energy to shore and the support for cross-zonal exchanges.
- **Offshore Generation (OG)**: generation unit (e.g. wind farm) located offshore that can be connected to the shore via a feed-in line (radial connection) or an **offshore hybrid asset**.
- **Offshore Hybrid Project** is a project combining OG and Offshore Hybrid Assets.
- **Offshore hub** (with or without OG being directly connected) relates to a node in an offshore grid.

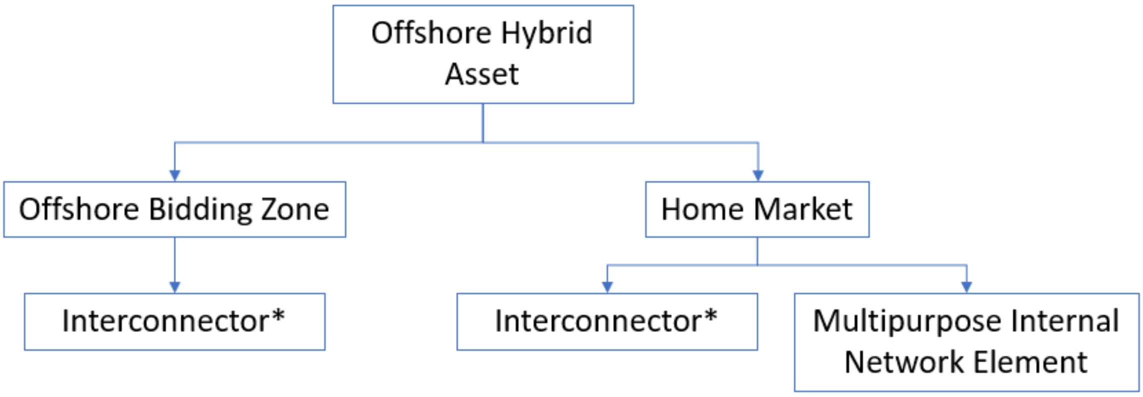


Figure 1 Definition of transmission assets in an Offshore Hybrid Project

- **MACZT**: margin available for cross-zonal trade for a given market time unit. It can be expressed in absolute (MW) or in relative value (% of Fmax, which is the maximum transmission capacity of a network element).

[13] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity
[14] E-Reg Art 2.1
[15] E-Reg Recital 66

C. Market arrangements for an offshore hybrid project

The goal of this section is first to present Eurelectric's selected market arrangements that will be further analysed in this paper.

Home Market

In an HM setup, the OG bids into its onshore BZ. The OG can freely trade its produced energy with market parties located within the same bidding zone. OG has unconstrained commercial access to its home BZ.

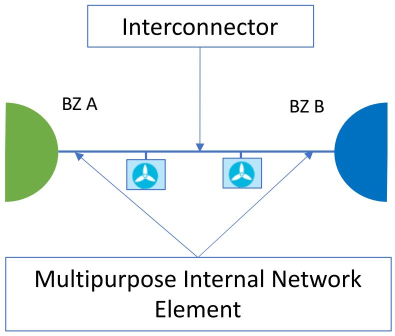


Figure 2 Illustration of the HM setup with relevant transmission assets connecting two BZ (green & blue)

There are mainly two options[16] to allocate cross-zonal capacity, called HM-EXEM (from *exemption*) and HM-COMP (from *compliant*) in the rest of the document and that are described hereunder:

HM-EXEM: the cross-zonal capacity (on the MINE and internal network element) made available for cross-zonal trade is calculated based on the installed transmission capacity decreased by the forecasted OG production. The Art 16.8 E-Reg remains of application on the transmission capacity that is not pre-allocated to the forecasted OG production. Because of the unconstrained access of OG production to the transmission capacity, depending on the relative size of the transmission and generation assets, there will be moments when the 70% threshold imposed by the Art 16.8 E-Reg (also defined as the minimum value of MACZT) cannot be respected without causing market congestion leading to redispatching and countertrading actions.

This non-compliance can be resolved by granting an exemption following a derogation process under Art. 63 (for merchant interconnectors) or Art 64 E-Reg17. The exemption would apply to the MINE and on internal network elements, provided those last ones are

[16]This is without considering a third option: define and implement a more efficient approach to set the minimum threshold of margin available for cross-zonal trades (probably through a new legislative act revising Art 16.8). From this perspective, Eurelectric highlights its proposals on ambitious yet efficient capacity calculation approaches detailed in the paper of Eurelectric, EFET and the MPP on efficient capacity calculation methodologies for an efficient European electricity market on June 2018, where ACER would be in charge of defining the appropriate level of MACZT for every border based on efficiency-driven principles. This option will be treated similarly to the HM-EXEM, as the result is the same, only the legislative process to get there differs.

[17] Though it can be questioned if a 10-year derogation as provided for the Kriegers Flak Combined Grid solution would provide enough clarity to take the investment decision

considered as a critical network element in the capacity calculation. The IC will not be subject to an exemption and should be able to comply with Art 16.8.

The lower value of MAZCT on the MINE of one of the onshore BZ follows this equation:

$$MinMACZT_{MINE_{BZx}} = \left(Capacity_{MINE_{BZx}} - ForecastedProd_{OG_{BZx}}\right) * 0{,}7$$

The maximum value of the MACZT follows this equation. It is expected that this upper value will be applied most of the time given the fact that when the OG forecasted production is deducted, all the remaining capacity should be made available to the market (because there are no loop flows or other form of unscheduled/internal flows on the MINE).

$$MaxMACZT_{MINE_{BZx}} = \left(Capacity_{MINE_{BZx}} - ForecastedProd_{OG_{BZx}}\right)$$

In the graph hereunder that serves as an illustration, it is assumed that both OG capacities (in BZ A and BZ B) and both MINE installed capacities are equal. For the lower value, the Art 16.8 threshold is applied to the remaining transmission capacity whereas the upper value is the remaining transmission capacity.

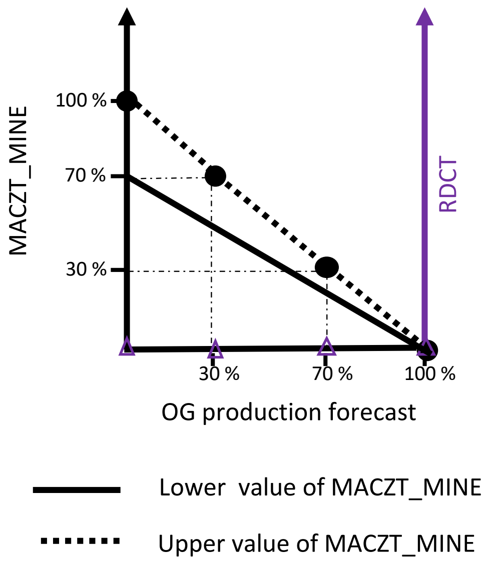


Figure 3 Available CZ capacity for commercial trades & potential need for Redispatching and Countertrading (RD&CT) in the function of the OG production under HM-EXEM setup

Regarding the application of the exemption on the internal network element, this is quite similar. The only difference is that it is expected that the upper value will not be encountered as often as on the MINE because of the existence of other types of flows on those internal network elements, such as loop flows or internal flows[18].

The DA price the OG is exposed to is the DA price of the home BZ, independently of the direction of the final physical flow on the MINE and IC.

[18] For the completeness of the reasoning, another approach would consist of considering the OG flows as internal flows when flowing on internal network elements and apply the Art 16.8 requirements on those elements. This would allow to limit the exemption to the MINE but would probably also cause congestion on internal network element not being able to accomodate both internal flows (parlty composed of OG production), loopflows, reliability margin and at the same time provide 70% for CZ commercial trades. Costly remedial actions would be needed to solve those congestion, which is exactly what the HM-EXEM setup aims to avoid.

The minimum value set under the Art 16.8 of E-Reg (and more generally the availability of MINE) will not directly impact the OG, as it is hedged against any capacity limitation by having unconstrained commercial access to its bidding zone.

HM-COMP: the cross-zonal capacity made available for cross-zonal trade on the MINE is made compliant with Art 16.8 E-Reg independently of the forecasted OG production. This might imply physical congestion on one of the MINE that requires remedial actions after the DA market for which the volume associated is linked to the percentage set in Art 16.8 E-Reg.

The lower value of MAZCT on the MINE of one of the onshore BZ follows this equation:

$$MinMACZT_{MINE_{BZx}} = \left(Capacity_{MINE_{BZx}}\right) * 0{,}7$$

The upper-value MAZCT on the MINE of one of the onshore BZ follows this equation:

$$MaxMACZT_{MINE_{BZx}} = Max\ (MinMACZT_{MINE_{BZx}};\ Capacity_{MINE_{BZx}} - ForecastedProd_{OG_{BZx}})$$

This is shown in the graph below where it is equally assumed that installed transmission capacity (MINE and IC) is equal to the OG capacity. As in the previous graph, and under this assumption, it is expected that if the OG forecasted production is lower than 30%, then the TSO would be able to provide more than 70% of the physical CZ capacity for commercial trades. Moreover, when the OG forecasted production is above 30%., it is expected that RDCT volumes will have to be applied, proportionally to the OG forecasted production over the 30%.

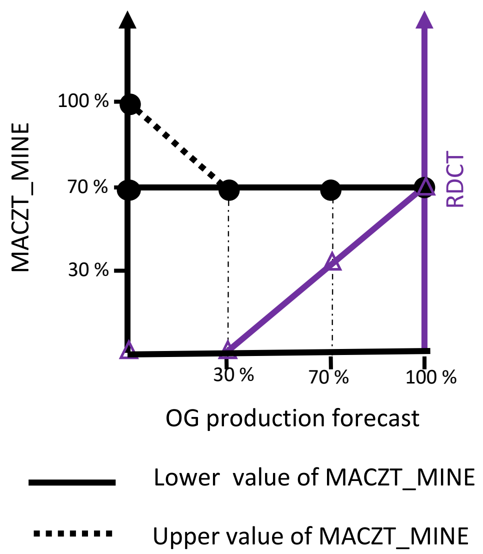


Figure 4 Available CZ capacity for commercial trades & potential need for RDCT in the function of the OG production forecast under HM-COMP setup

It could also be possible that the MINE is dimensioned largely enough to allow the full production of the OG together with being compliant with the Art 16.8 of E-Reg. The required over-, under-dimensioning of the MINE, OG, respectively, would be dependent on the threshold under Art 16.8 E-Reg. However, this specific combination of OG and offshore hybrid asset's capacities will not be considered in this paper as it potentially undermines the cost savings from dual-use offshore hybrid infrastructure and does not allow to explore the different challenges an offshore hybrid project might encounter under an HM setup.

Also, it should be noted that depending on the relative size of the OG capacity compared to the MINE capacity, there can be a significant part of the time[19] where the Offshore Hybrid Assets will be able to accommodate both CZ commercial flows and OG production at the same time, respecting the Art 16.8 of E-Regulation. More specifically, this will be the case when OG production is below 30% of the Offshore Hybrid Asset installed capacities (under the assumption that MINE and IC have the same capacity), e.g. when no wind drives offshore wind turbines.

The OG is exposed to the DA price of the home BZ, independently of the direction of the final physical flow on the MINE and IC.

The minimum value set under the Art 16.8 of E-Reg (and more generally the availability of MINE) will not directly impact the OG, as it is hedged against any capacity limitation by having unconstrained commercial access to its bidding zone.

Offshore Bidding Zone

In an OBZ setup, the OG is placed in its own offshore bidding zone. The OG bids into the OBZ. To trade the energy produced, the OG has to compete (implicitly) with onshore energy bids for access to cross-zonal capacities over the IC (as long as there is no demand in the OBZ in which case the produced energy could be bought and consumed within the OBZ).

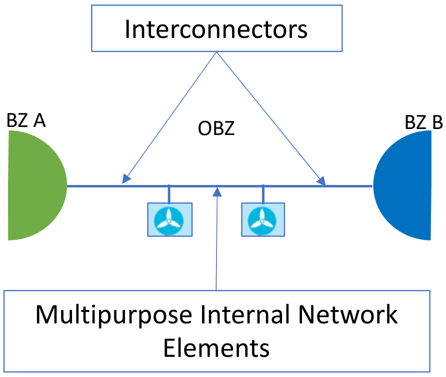


Figure 5 Illustration of the OBZ setup with relevant transmission assets connecting three BZ (green, yellow & blue)

The DA price captured by the OG is the DA price of the OBZ which is defined by the market coupling algorithm. This price is equal to the price of the BZ towards which the cross-zonal capacity is not constrained[20] [21] as a result of the market coupling. The allocation process of CZ capacity between the OBZ and the onshore bidding zones (or other OBZ) is the same as any other cross-zonal capacity allocation in the EU, despite its dual-use nature (OG feeder line & interconnector). As shown in the graph below, the minimum of 70% is provided independently of the OG forecast in compliance with Art 16.8 E-Reg.

$$MinMACZT_{IC} = (Capacity_{IC}) * 0{,}7$$

[19] This is relevant in the case of wind offshore (and related load factor 39-47% - BEIS Study)

[20] There are offshore hybrid project configurations where the OBZ price could be equal to the marginal cost of the local production (read 0). This is when then sum of the interconnector capacities is equal or smaller than the OG capacity, which creates a simultaneous congestion of all interconnectors.

[21] It has to be noticed that the price could be set at 0 in the OBZ even in case not all interconnectors are simultaneously congested (see Annex).

Art 16.8 provides certainty on a lower value of the MACZT on the ICs but we expect it to be most of the time equal to the upper value, being the physical capacity. This is because, due to the HVDC nature of the IC, there is no loop flows, internal flows nor unscheduled flows.

$$MaxMACZT_{IC} = Capacity_{IC}$$

There is no need for RDCT volume after the DA process as congestion management is embedded in the CZ capacity allocation process.

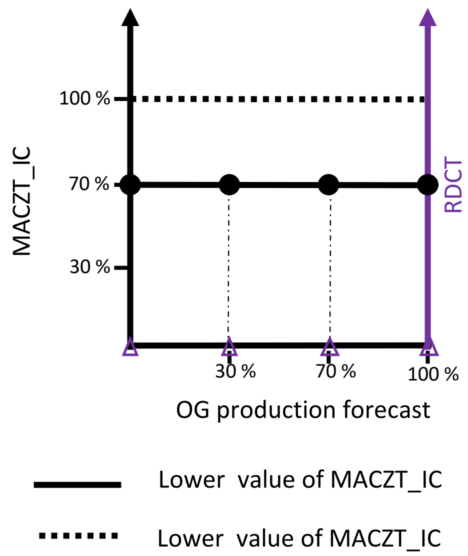


Figure 6 Available CZ capacity for commercial trades & potential need for RD&CT in the function of the OG production forecast under OBZ setup

D. Impact Assessment over the different market timeframes

In this chapter, Eurelectric assesses the impacts to be considered in the different market timeframes for the main market arrangement options presented above.

Forward Capacity Calculation and Allocation

From an OG perspective, and like any power generator, there is an exposure to price risks that need to be (at least partially) hedged in order to decrease the exposure towards variable (and potentially low) short term prices.

In the **HM setup**, the OG has direct access to the liquid forward/futures market (up to three years ahead) where part of its forecasted production can be sold, as any onshore generation. Moreover, OG can buy Long-Term Transmission Right (LTTR) to access higher forward prices in neighbouring BZ.

In the **OBZ setup**, OG is exposed to lower prices as a consequence of the local generation/demand pattern coupled with the risk of potential congested ICs. Being exposed to lower prices risks, the OG would secure revenues on forward/futures markets. However, it is highly likely that it will have to be done cross-border by buying LTTR given the limited liquidity in the OBZ. The price OG is willing to pay for LTTR will depend on the forecasted spread between the neighbouring BZs.

For OG in an OBZ setup, the process of acquiring has a cost, notably in terms of premium when considering the risks taken (e.g., LTTR might not be sufficient to reach the planned hedging ratio). Therefore, it does not completely alleviate the consequences of the distributive effect elaborated in the next chapter. Based on this observation, potential redistribution schemes are discussed in a dedicated chapter.

From an IC owner perspective, the responsibility lies in the calculation and the allocation of LLTR (being physical or financial). The choice of market arrangements has consequences on how to perform that.

In the **HM-EXEM**, the TSO will have to make assumptions on the forecasted production of OG to perform the long-term capacity calculation. This is unrealistic for forward timeframes, especially for an intermittent and variable generation. In order to minimize the financial risk associated with the Financial Transmission Right (FTR) reimbursement at the DA market spread, TSOs will tend to limit the volume of FTR to be auctioned in the forward timeframe, potentially to the capacity of the MINE capacity minus the OG capacity. Such a limitation would reduce the volume of LTTR to be allocated, and hence could be detrimental to market parties who want to hedge the locational spread.

In the **HM-COMP and OBZ setups**, nothing prevents the TSOs to offer at least 70% of the MINE capacity in the forward timeframe because this capacity will anyway be made available to cross-zonal trades in the DA timeframe, under normal circumstances (no outage or technical limitations).

Day-Ahead Capacity Calculation

The DA capacity calculation (DA CC) process consists of determining the cross-zonal transmission capacity that is made available for cross-zonal trades at the DA auction. The different cases explained below only concern the DA Capacity Calculation of the Offshore Hybrid Assets (MINE and IC). It should be noted that internal network elements to BZ, other than the MINE, can also constraint cross-zonal exchanges if there are limiting constraints in the market coupling algorithm.

Under the **HM-EXEM** setup, the forecasted production of OG has a direct impact on the CZ capacity made available for the trades on the MINE. As such the cross-zonal capacity on the IC provided for cross-zonal exchanges should not be limited by the forecasted OG production and should comply with the threshold set in the Art 16.8 E-Reg. The DA CC is a prerogative of TSOs (supported by RCC) for which they are accountable. It is then likely that TSOs will want to calculate themselves the forecasted production of OG.

One possible issue is that, depending on the TSOs incentive structure, TSO might be tempted to under or over-estimate the OG's production to impact the MACZT[22] on the MINE

[22] Defined in the recommendation No 01/2019 of the European Union Agency for the cooperation of energy regulators
https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2001-2019.pdf

in a way to maximize its incomes from the congestion rent or minimize its Redispatching and Countertrading (RDCT) costs, respectively.

If, on the contrary, the OG's Balancing Responsible Party (BRP) forecast is used as an input for the DA CC, it creates the possibility for market manipulation as the forecast will directly influence the MACZT preventing cheaper generation to be transported in higher priced BZ, hence influencing the prices of each BZ.

As the two previous options might be pernicious in terms of incentives, **Eurelectric is insisting on the increasing and important role of Regional Coordination Centres.** When it remains the prerogative of TSO to provide an Individual Grid Model and the data it contains, it should be allowed for the RCC to modify the generation data (especially in the framework of an offshore hybrid project given the direct link between generation forecast and CZ capacity) in the Common Grid Model based on their own forecast. This should be included in the discussion concerning the revision of the Capacity Allocation and Congestion Management Guideline (CACM GL).

Under the **HM-COMP** setup, the OG forecasted production has no direct impact on the minimal value of the MACZT. However, it is a relevant indicator of the remedial actions the HM TSO will have to activate internally or across borders after the DA capacity allocation to accommodate the potential over-allocation of scarce MINE capacity.

Under the **OBZ** setup, the DA CC process is more straightforward as assumptions on the OG forecasted production do not, to the same extent, impact the MAZCT on the ICs[23]. All export capacity for the OG will be subject to DA CC by TSOs. In a normal (ideal) situation, all the IC nominal capacity can be made available for cross-zonal trades (HVDC link/grid with no loop flows nor internal flows) complying with the principle laid out in Art 16.4 of E-Reg. The same can apply to the MINE comprised within the OBZ.

Day-Ahead Capacity Allocation

Under each market arrangement under consideration, the way CZ capacities are allocated is the same. The assumption taken for the allocation of CZ capacities on MINEs and ICs is that this is done implicitly during the market coupling algorithm, in line with the EU target model for electricity markets.

What differentiates the market arrangement is the ability of the OG to benefit from a priority access to the transmission capacity, what level of MACZT there is to allocate and how it relates to the OG production forecast and whether or not the allocation process can lead to congestion after the DA MC.

Those differences are summarized in the table hereunder. Please refer to figure 2 and 5 to correctly differentiate the MINE and the IC under the different market arrangements. Moreover, it is assumed that each offshore hybrid asset can accommodate the OG production.

[23] However, the OG production forecast might have an impact on the result of CC on other borders because the production data (forecast or reference) is used in the IGM, CGM which are used for the capacity calculation.

	HM-COMP	HM-EXEM	OBZ
OG priority access to transmission capacity	Yes, on the MINE		No
MACZT_IC	[70%;100%]		
MACZT_MINE	[70%;100%]	[70%;100%] of (MINE capacity - OG forecasted production)	[70%;100%]
Potential market congestion just after DA MC	Yes, on the MINE	No	No

Table 1 While the CZ capacity is allocated implicitly for all market arrangement, input data to the allocation process differ.

The consequences of those differences in the input of the DA capacity allocation process are looked at from three viewpoints: **efficiency of the *final* dispatch**, market **revenues distribution** between OG and ICs owners and need for (and impact of) **corrective measures** by TSO.

The results are summarized here below in the figure and are further elaborated in this section by using a straightforward example. More elaborated examples can be found in the annexes.

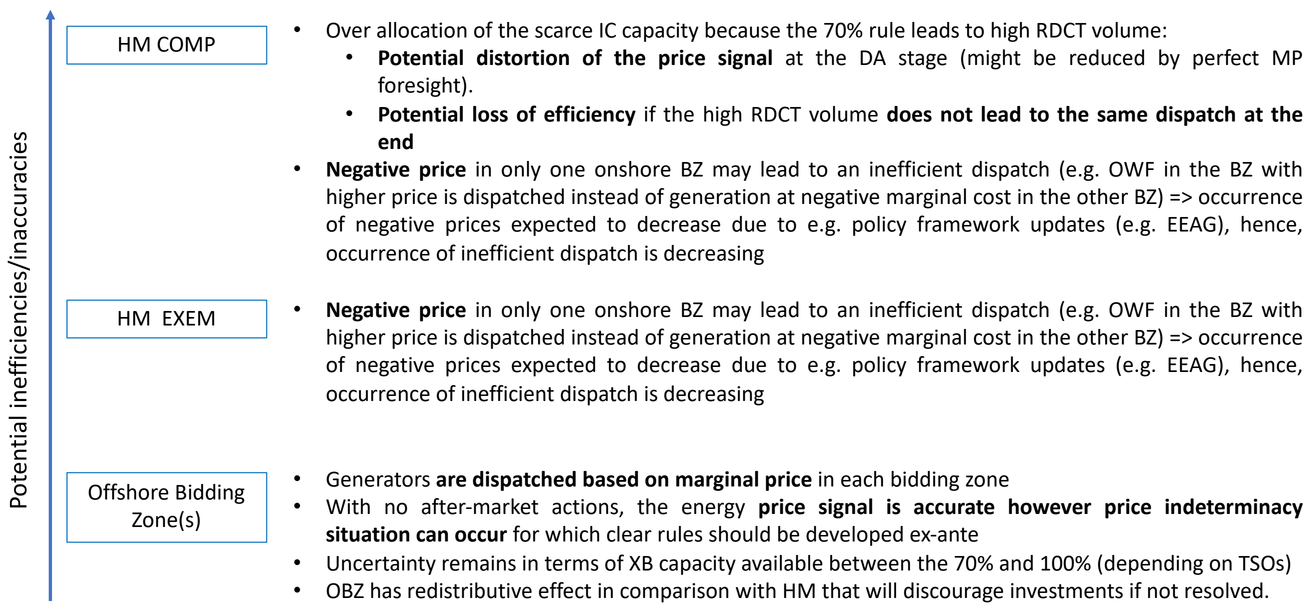


Figure 7 Comparison of HM-COMP, HM-EXEM and OBZ in terms of efficiency of market dispatch and accuracy of DA energy price signal

Distributive effect

The distributive effect materializes by the transfer of part of the SEW under the form of the producer surplus to the form of congestion rent for the IC owner[24].

[24] 'socio-economic welfare' means the aggregation of the economic surpluses of electricity consumers, producers, and transmission network owners (congestion revenue)

The simplified examples hereunder show this effect when comparing the same situation (regarding transmission capacity and topology and OG energy bids) under an HM-EXEM, HM-COMP and an OBZ setup.

In the **HM-EXEM setup,** the OG belongs to the high price BZ benefitting from high revenues. It is considered that in such setups, the MINE connecting the OG to its home BZ is a regulated asset that does not get congestion rent as it is entirely located within a single BZ[25]. Any price spread materializing between both onshore BZ which leads to a congestion rent will be allocated to the IC between both BZ. The MACZT_MINE is taking into account the forecasted OG production.

In the **OBZ setup**, both ICs connecting each side of the OBZ to one onshore BZ are entitled to get congestion rent if a price spread (with allocated volume) materializes on the BZ border it is spanning.

One can observe that the high revenue the OG is getting by belonging to the BZ B under the HM-EXEM setup is transferred as congestion rent for the IC linking the OBZ and the BZ B under the OBZ setup.

In order to have an exhaustive analysis, the **HM-COMP setup** is also displayed. In that case, MACZT_MINE is not taking into account the forecasted OG production and is at least equal to the threshold set under Art 16. 8 of E-Reg. In our example, it means that more capacity is made available for trades between both onshore BZ compared to the HM-EXEM setup. This will have no impact on the OG's revenue that is any case accessing the Home BZ. The IC linking both onshore BZ will however collect more congestion rent as more trade can be matched across the BZ border[26].

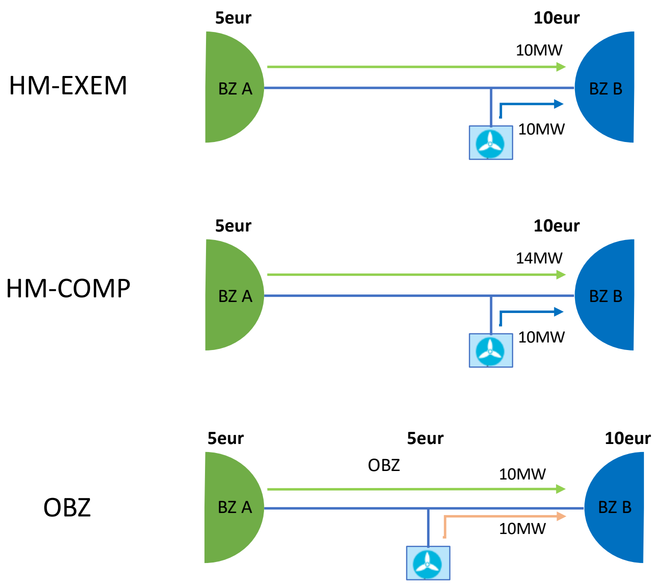


Figure 8 Example of capacity (pre-) allocation on the MINE and IC for all three market arrangements

[25] Note that the congestion rent is a priori captured by the IC owner (in case of merchant investment) or shared by the two respective TSOs (in case of regulated common investment).
[26] In order to keep the example understandable, it is assumed that this higher volume of exchange between both onshore BZ does not impact the market clearing price.

	The physical capacity of each network element connecting OG to shore	MACZT		
		HM-EXEM	HM-COMP	OBZ
BZ_A to OG	20	[0,7;1]*20=[14;20]	1*20=20	1*20=20
OG to BZ_B		[0,7;1]*(20-10)=[7;10]	0,7*20=14	1*20=20
Active constraint	/	**10[27]**	**14**	**20**

Table 2 Comparison of the physical transmission capacities with the capacities made available for the market (MACZT)

	OG revenues	IC revenues	OG+IC	RDCT volume[28]
HM-EXEM	10*10=100eur	10*5=50eur	150eur	0
HM-COMP		14*5= 70eur	170eur	4MW
OBZ	10*5=50eur	20*5=100eur	150eur	0

Table 3 Illustration of the distributive effect impacting market revenues for the OG and the IC owners as well as the redispatching and countertrading volume needed to accommodate congestion

Impact of RD&CT on DA price signals

In the **HM-COMP** setup, TSOs can be exposed to market congestions on the MINE that have to be resolved by the activation of costly remedial actions after the DA Market Coupling.

First of all, the activation of RDCT after the DA MC may lead to potential distortions of the DA prices in each onshore BZ[29] compared to a situation where the calculated MACZT reflects the physical capabilities of the network. The exporting BZ exported more than what was physically bearable, pushing the prices upwards. Similarly, the importing BZ imported more than what was physically bearable, pushing the prices downwards. The importing BZ needs to increase the production onshore via generation units that were probably out-of-the-money at the DA stage and that would if selected to meet local demand in DA, have increased the market-clearing price of the importing BZ.

Second, depending on the RDCT management by TSOs, needed to alleviate the market congestion on the MINE (especially their level of coordination), the final dispatch can turn out to be different than in the OBZ or the HM-EXEM setup. A different dispatch would mean a higher generation cost leading to a decrease of the SEW under the **HM-COMP** setup. For example, if a lack of coordination between both onshore TSOs prevents the activation of CT, the importing TSO would need to curtail IG production.

Impact of negative prices on the final dispatch

Negative clearing prices in the DA market can occur. Those are mainly due to support schemes that are not designed to properly react to the market price. In the context of

[27] As explained earlier, we expect the upper value of MAZCT to be applied on the MINE

[28] RD&CT cost is not displayed here; if perfect cross-border RDCT is assumed, the final SEW would be identical to the other cases.

[29] This distortion can however be mitigated by speculative behaviors across timeframes, if the applicable market rules allow them.

offshore hybrid projects, negative prices in onshore BZ can have a not desirable impact on the efficiency of dispatch when the HM setup is implemented.

Under an **OBZ setup**, the IC capacity is allocated to energy bids that maximize the SEW. Under an **HM-EXEM** setup, part of the MINE capacity is pre-allocated to the OG, independently of any price consideration. This ex-ante allocation can prevent cheaper generation to flow energy to the high price, importing onshore BZ.

This is particularly obvious when the price in one BZ is negative (lower than the marginal cost of production of the OG) as illustrated in the figure below.

Only under the **OBZ** setup, the cheap generation located in BZ_A can flow to BZ_B and fully utilize the ICs capacity (up to the MACZT). The OG is not dispatched. Under the **HM-EXEM setup**, the pre-allocation of part of the MINE capacity to the OG production only allows the remaining capacity on the MINE to accommodate commercial flows from BZ_A. OG is dispatched whereas having a higher marginal production cost than the generation in BZ_A. The less efficient dispatch characterized by higher generation costs leads to a lower SEW than under an OBZ setup. This effect is less acute under an **HM-COMP** setup as a minimum value for the MAZCT on the MINE is foreseen. However, this does anyway lead to market congestion on the MINE requiring RDCT.

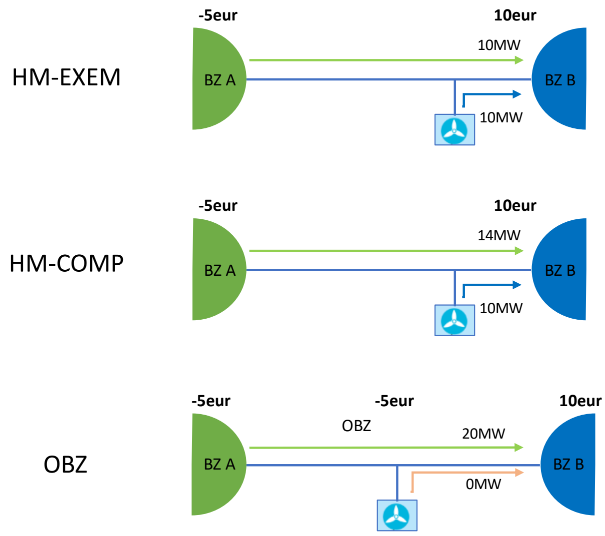


Figure 9 Example of capacity (pre-) allocation on the MINE and IC for all three market arrangements with negative price in one onshore BZ (BZ A)

It should be repeated that a major cause of negative prices nowadays is the bad design of some support schemes such as feed-in tariffs; this kind of support schemes is expected to be phased out in the future (cf. § (124)(c) of the Guidelines on State aid for environmental protection and energy 2014-2020: "*measures are put in place to ensure that generators have no incentive to generate electricity under negative prices*"), which should strongly alleviate the issue.

In general, and when considering positive clearing prices in all BZs[30], the **DA final dispatch in the HM-EXEM or the OBZ is the same**.

[30] The exact condition is: when marginal production cost of the OG is lower than the one(s) of the onshore BZs, then the dispatch is the same, provided there is no structural congestion on the feed-in line, i.e. it is able to transport the full power of the offshore generator to the shore of the bidding zone in which this generator is located (if this last condition is not fulfilled, the property still holds with perfect cross-border redispatch).

Other considerations

A particularity in the OBZ approach is the interplay between the MACZT of both ICs and consequently the question of which IC will cause the price decoupling as the answer to that question determines which IC owner will collect the congestion rent. In order to illustrate that, let's consider a case where there is no production in the OBZ (e.g. no wind). In that case, the IC which has the smallest MACZT will see the price spread (as it is the constraining element), hence its owner will receive the full congestion rent[31]. This can be observed in the figure hereunder where there is no OG production and where the commercial flow is in the direction BZ B to BZ A through OBZ (blue arrow). It has to be noted that this situation can occur in the same way with a (forecasted) commercial flow in the other direction as an IC collects a congestion rent whenever there is a price spread and a fully used capacity. Two situations are depicted (red and black), showing how the difference between the MAZCT of both ICs, can impact the location of the congestion.

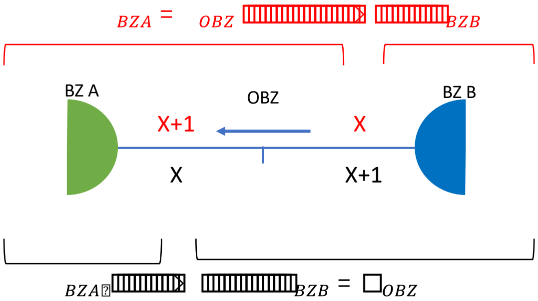


Figure 10 In function of the MACZT (X or X+1), the congestion is placed on the left (black case) or right IC (red case)

This creates pernicious incentives for the TSOs to limit the CZ capacity just under one of the other interconnectors[32]. One possible way to disincentivize this behaviour would be to redistribute the congestion rent, initially collected by one single IC owner, to both of them proportionally to their respective MACZT. This would encourage TSOs to make as much CZ capacity available as technically possible. Eurelectric expects that this would be part of agreements between IC owners (notably through the review of the Congestion Income Distribution methodology according to article 73 of CACM).

Scheduling

Scheduling is the process where BRPs notify the TSOs what are their generation/consumption schedules. This takes place after the DA MC and often before the ID CC and CA.

The issue under consideration is the interaction between the results of the DA MC (hence the flows on MINE/IC) and the scheduling values of the OG.

In the **HM-EXEM** setup, it is clear that the TSOs forecast used to determine the MACZT on the MINE can differ from the OG owns forecast used later on in the scheduling process. This can be caused by using different data sources for the forecast or because forecasts closer

[31] Under the assumption that the interconnectors owners are different.

[32] This situation also occurs with a non-zero production (forecast) in the OBZ. But it complicates the explanation, as the IC owner which forecasts to not be the constraining element (BZ B is the example) should set its MACZT at maximum value equal to the one of the other IC diminished by the OG production forecast in order to become the constraining element.

to real-time tend to be of better quality or because OG is not dispatched at the end (due to price levels in the Home BZ). The question is then how to deal with discrepancies between the TSO forecast and the OG scheduling values, given the impact on the subsequent processes (such as ID CC).

- A lower value in the OG schedules compared to the HM TSO forecast used in the capacity calculation can result in situations where more CZ capacity could have been allocated for the DA MC. This prevents the efficient use of the offshore hybrid asset in the DA timeframe. The non-allocated capacity in DA has to be made available for the subsequent market timeframes (ID and Balancing).

- A higher value in the OG schedules compared to the HM TSO forecast used in the capacity calculation can also result in overload on the MINE or IC. This will lead to cost for the HM TSO that has to resolve that congestion via costly Remedial Actions (RA). This should, in any case, not lead to an uncompensated curtailment of the OG. The question of cost-sharing of costly RA amongst TSOs is not discussed here but remains a challenge, especially in the HM-EXEM setup that is based on derogations which bring uncertainties on the applicable rules.

In the **HM-COMP**, the OG schedule is superposed to the flow on the MINE resulting from the DA MC. Any overload will then be solved by the activation of costly RA by the HM TSO.

In the **OBZ setup**, the OG schedules will not per se be equal to the accepted bids resulting from the DA MC. As there is a time delay between the bid submission for the DA market and the gate closure time for submitting the schedules, OG's production forecast will certainly have evolved. However, the IC setpoint will take into account the MC results (translated in CZ exchange nominations) rather than the latest OG's schedules. Any adjustment of the OG portfolio will have to be performed via the ID or the BAL market by the OG's BRP itself. In comparison with HM-EXEM & COMP, there is a clear shift in terms of responsibilities from the TSOs to the OG's BRP, and also a clear shift in terms of who bear the costs linked to those discrepancies.

Intraday Capacity Calculation and Allocation33

ID capacity calculation (ID CC) process consists of determining the cross-zonal capacity that is made available for cross-zonal trades during the ID continuous market or at the ID auctions (regional or pan-EU).

The ID CZ capacity can be the DA CZ capacity leftovers (or from a previous ID trading period) or the result of an ID recalculation by the TSOs. It has to be noted that the ID CC process can also lead to a reduction of cross-zonal capacity that is often the consequence of the outage of the network element (CZ or internal).

In the **HM-EXEM** setup, the same challenges encountered in the DA CC arise. TSO has to take its latest forecast of the OG production (that will probably differ from the OG schedule) to calculate the capacity that can be released to the ID market[34].

[33] Assumption: Art 16 E-Reg only applies to the DA timeframe (cfr. ACER guidance).
[34] A change in the TSO OG's forecast is not the only case where the available CZ capacity changes. If the MINE was constrained during the DA CC & Allocation because of an onshore congestion, the situation might have evolved in ID, hence having an impact on the capacity available for the ID market.

As a reminder, the main difference between HM-COMP and HM-EXEM is the compliance with the Art 16.8 of E-reg. However, this article only applies to the DA timeframe, therefore there is no minimum cross-zonal capacity to be provided to the ID market apart from ensuring the firmness of the already allocated capacities in previous timeframes. As a consequence, there is no difference in treatment between the **HM-COMP and the HM-EXEM** setups in the ID timeframe.

Throughout the ID timeframe and towards RT, the OG will be exposed to variations of its production forecast. It has to be noted that in both **HM setups**, those variations can be traded without constraint by the OG's BRP on the local ID market in its Home BZ. And this independently of the remaining capacity for CZ trades on the MINE as calculated by the TSO, as a consequence of the unconstrained access to the MINE. This can result in RDCT actions to be applied by the TSOs in the ID timeframe, on top of the ones already applied after the DA MC under HM-EXEM setup.

THEMA presents several options to avoid RDCT action in ID following ID trading by the BRP, which Eurelectric **cannot** support:

1. Increase the Flow Reliability Margin on the (potentially) congested network element (e.g. MINE)[35].
   Eurelectric thinks this prevents efficient use of the transmission capacity as this margin is kept out of the market.
2. Withhold CZ capacity for ID trades (through Art 17.2 E-Reg).
   Eurelectric thinks that all capacity should be given to the market as soon as it is available as the future value of the IC cannot be assessed by the TSO at that time.
3. Restrict OG participation in the HM ID market.
   Eurelectric thinks this would be discriminatory against the offshore generator.

In the **OBZ setup**, as in the DA timeframe, the calculation is more straightforward. TSOs do not have to take into account OG's production forecast as those have no priority access to the IC. The ID capacity made available for CZ trades will be the leftovers of the DA Capacity Allocation if any, or any CZ capacity released (in one direction) as a consequence of CZ ID trades (in the other direction), or additional capacity following an ID recalculation.

When it comes to the allocation of ID cross-zonal capacity over ICs, the available capacity will be allocated through the Single Intraday Coupling, either via the continuous ID cross-border market (aka XBID) or via the future pan-European ID auctions.

As explained previously, both in the **HM** and in the **OBZ setup**, the OG can freely (without constraint) trade within its bidding zone (Home BZ and OBZ). However, this is without saying that the liquidity in the OBZ will be limited as long as there is a high concentration of the same type of market participants (e.g. OG at zero marginal cost). So that OG in an OBZ setup has, as an extra barrier compared to HM setup, the need to get ID cross-zonal capacity to access neighbouring markets. First, there might not be sufficient ID capacity leading to a risk of volatile prices in the ID timeframes. Second, as per the ACER decision on the implementation of pan-EU ID auctions to price the CZ capacity in ID, OG might have to pay for it whereas, in the ID continuous market, CZ capacity is allocated for free.

[35] Market Arrangements for Offshore Hybrid Projects in the North Sea - Report written by THEMA Consulting Group for European Commission

Congestion Management

Congestion management (CM) by use of RDCT is applied by TSOs when a network element is (forecasted to be) overloaded and often when non-costly RA cannot alleviate the congestion. CM can be applied preventively or curatively to solve forecasted or real congestion situation, respectively.

As a general statement, the regional coordination of remedial actions as mandated by the CACM GL and SO GL should lead to the most efficient solution, when effectively applied. This should obviously also apply to CM related to offshore hybrid project's operation.

Congestion Management can take place at all timeframes and concern all network elements. However, in the context of our paper, preventive CM to solve the congestion on the MINE and the IC is the main focus.

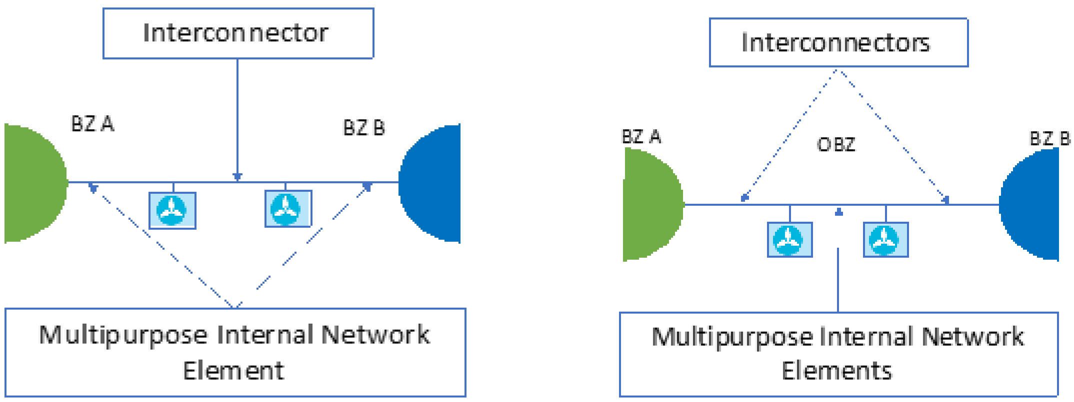


Figure 11 Reminder of the terminology applied to transmission assets in the function of the market setup

One can distinguish CM actions based on the timeframe where they are applied: before, during or after the DA market coupling.

When TSOs might fail to provide the nominal capacity to the day-ahead market to be able to export the OG energy that could have been generated, **CM before the DA market coupling is needed**. CM will consist of a curtailment of the production in order to prevent the congestion to materialize. This can be caused by:

- Some delays in onshore/offshore grid development (on the MINE or the IC);
- Unavailability of one of the onshore/offshore transmission assets;
- TSO deeming necessary to limit cross-zonal capacity for system security reasons.

In case of curtailment due to grid constraints, radially connected OG and onshore renewable generators are compensated by TSOs (as part of their connection contract). We might expect this would also be the case of any OG under **HM or OBZ setup**.

The general principles are laid out in Art. 13 of E-Reg according to which involuntary curtailment (non-market-based downward redispatching) should be applied to renewable energy as a last resort and be financially compensated.

While this seems straightforward to apply those general principles for OG under an HM setup (notably via the consideration of the MINE which is an internal element), this is more complicated when considering OBZ. If the calculated export capacity from the OBZ is smaller than the OG forecasted production, and if no CM before MC is put in place, the price in the OBZ will collapse to zero, leading to the economical curtailment of OG, solving any congestion issue at the same time but leaving OG with no revenue eventually. From a level playing field and with regards to the Art 13 E-Reg, **Eurelectric deems it not acceptable**. It is not because congestion management could have been solved via the market coupling algorithm, that no compensation should be foreseen **in the specific case of not having sufficient cross-zonal available capacity to export all OG production.**

It must be ensured that the same rules apply to all renewable energy generation, even if placed in an OBZ. The rules and compensation models for firm access to transmission capacity for OG in OBZ need to be developed at the regional level (via harmonized connection contract) by the TSOs sharing the responsibility for capacity availability in the offshore and neighbouring onshore grids. Failing to do so would leave potential generators with a prohibitively high risk. One also has to take into account the required cooperation between TSOs, IC owners and MPs for organizing the compensation and the related rules as this is not as straightforward as a limitation on a MINE for which an agreement with only the HM TSO is needed.

Should the transmission capacity be sufficient to accommodate OG production, then there is no reason to apply MC before CM and the process can continue thru the DA CA.

During DA market coupling, congestion management on network element taken into account as constraint takes place implicitly via the market coupling algorithm. This prevents over-allocation of capacity on those specific network elements.

In any of the market arrangement under consideration, the market coupling algorithm will apply. The only difference is the level to which the constraint (materialized by the MACZT on the Critical Network Element) takes into account the physical reality of the network while considering the OG production forecast).

Under the **HM-COMP** setup, the MACZT is set at, at least, 70% whereas under the **HM-EXEM** setup, it is comprised under 0 and 100% of the nominal capacity of the MINE, depending on the OG production forecast.

Under the **OBZ and HM-EXEM setup**, CZ congestion management is fully internalized in the market coupling process that will not allocate more CZ capacity than what is available on ICs and MINEs (taking into account OG production forecast in the HM-EXEM setup).

Therefore, if OG bids (read OG production forecast) exceed available transmission capacity on ICs – a situation that would have been ideally solved via CM before MC), the price in the OBZ will collapse to 0. **The risk of having a low price (potentially zero) is higher for an OG in an OBZ than in an HM setup[36], this can be tackled through compensation mechanisms as described in CM before CM.** In any case, and independently of the previous point, the OG will structurally get the lower price of the neighbouring BZ. The impact of this can be mitigated through several means, which are discussed in the section *Distributive effect*.

After DA market coupling, TSOs can activate market-based RA to ensure the firmness of the already allocated capacity (in LT, DA and potentially ID timeframes). The main causes can

[36] This statement is highly dependent to the topology of the offshore grid. The higher the degree to which an offshore transmission is meshed, the lower the risk of not having sufficient transmission capacity to export OG power.

be over-allocation of cross-zonal capacity during the MC (cfr. HM-COMP), an outage/limitation of/on of any transmission element.

HM-COMP setup might structurally count on CM after MC (but also in the HM-EXEM in the ID timeframe). For example, in the case of import towards HM BZ and a congested MINE, the RA activated by the HM TSO can be the following:

- Internal Redispatching: by curtailing OG's production and increase the production elsewhere in the HM BZ. If the cost of upward redispatching is higher than the marginal cost in the neighbouring BZ, this will lead to an inefficient dispatch.
- CZ Redispatching or Countertrading: by increasing production in the HM BZ and decreasing the production in the neighbouring BZ.

Under any market arrangement, RDCT activation might be needed (preventively or curatively) in case of unexpected line failures or other limitations of transmission capacity after the DA capacity calculation. As for any other generator, the OG would be mechanically protected from the financial effect of this generation reduction (i.e.: by its DA revenue). RDCT activation after MC is sometimes compensated cost-based or market-based as it depends on the market design in each MS (and no harmonization is foreseen for the time being) but at least the incurred costs should be compensated.

The use of CM under the different market arrangements (with DA Market Coupling as time reference) can be summarized as follows:

	CM before MC via curtailment	CM during MC via the MC algorithm	CM after MC via RD&CT
OBZ	Yes, with compensation in case of IC or MINE outage/restriction	Yes (MACZT on IC >=70%)	Low need
HM-EXEM		Yes but no impact for OG (MACZT_MINE >0% & <100%)	Moderate need (ID correction)
HM-COMP		Yes but no impact for OG (MACZT_MINE & MACZT_IC>70%)	High need (DA and ID correction)

Table 4 Use of congestion management under the different market arrangements

Balancing & Imbalance Settlement Price

The question of balancing applies to offshore hybrid projects as any other electrical system. From the simpler configuration (as illustrated in the examples used in this paper) to a meshed offshore grid composed of several generations and consumption nodes, the balance between generation and consumption must be ensured at any time.

Eurelectric would like to recall those basic principles related to the roles and responsibilities of TSOs and BRPs in terms of balancing and which should also apply to offshore hybrid projects, whatever the market arrangement:

- The role of the Balance Responsible Party (BRP) is well defined under the Art 17 EB GL.
  - The BRP is financially responsible for its imbalances.
  - In real-time, each balance responsible party shall strive to be balanced or help the power system to be balanced.

- This imbalance is to be settled by the connecting TSO meaning the TSO that operates the scheduling area in which balancing service providers (BSP) and BRP shall be compliant with the terms and conditions related to balancing.
- Following Art 54/55 EB GL, each TSO should calculate the imbalance price per imbalance price area, which corresponds to a scheduling area, often corresponding to the BZ.
- The BRP is responsible for energy per Imbalance Settlement Period (15 min as target), so any fluctuations in generation/consumption during the ISP would not be part of the financial responsibility of the BRP.

Currently, planned offshore hybrid projects are composed of HVDC transmission elements. This poses technical challenges in order to link the power setpoint of the transmission element (MINE or IC) to the real-time (RT) balance status of the offshore hub. Those will not be covered here as this is more related to technical challenges than market integration ones. Therefore, the following realistic assumption is taken: HVDC transmission elements setpoint can be tuned in RT in order to accommodate any imbalance situation in the offshore hub. Independently of the balancing economics considerations, any physical deviation from the last approved schedule at the offshore hub (the one used as an input for setting the flow on the MINE/IC) must be transported onshore, unless it is balanced directly at the OG location[37].

From that point on, it is important to develop what balancing products can be used to maintain the balance in the offshore hub, how the balancing energy will be priced, what role will the MINE/IC play in relation to the participation in the EU balancing platforms (PICASSO, MARI and TERRE) and what imbalance settlement price can be applied to imbalance volumes observed at the offshore hub.

For both HM and OBZ setup, it makes sense to use the EU Balancing Platforms[38] to maintain the balance in the offshore hub. The long/short position can be taken care of in the adjacent onshore Bidding Zones through the EU balancing platforms. This makes the most sense from SEW point of view, taking efficiently into account CZ congestion by using EU balancing platforms such as PICASSO (and the related IGCC), MARI or TERRE (if RR products are to be used).

For both **HM setups**, it will require to include the MINE as a constraint in the algorithms of EU BAL platforms while not considering it as a network element to another Scheduling Area/Bidding Zone. This is needed so that the EU BAL platforms can take into account the remaining available capacity on the MINE in both directions (while not considered as a cross-border element as such) that can be used to balance the system at the offshore hub. This requirement has to be further elaborated as it would probably entail the creation of a sub-scheduling area. Under the **OBZ setup**, the inclusion of the IC as a constraint in the algorithms of EU BAL platforms is more straightforward as the IC is linking two different Scheduling Area/Bidding Zone.

In any case, **the OG's BRP is only exposed to the Home BZ imbalance price** (which can be influenced by balancing energy bids activated outside his BZ, via the concept of Cross Border Marginal Price used in the EU BAL platforms).

It should be noted that in an **HM setup**, an additional challenge can take place after the ID (XB) GCT. Let's consider an OG's BRP observing a forecast error in its OG production, after

[37] Via other OG or other assets than OG like demand or storage facilities.
[38] The case of offshore hybrid project where a third country TSO (not an EU MS) is involved raises may other challenges as the participation to EU BAL Platform is not ensured.

the ID GCT. Under an OBZ setup, the OG would have limited means to avoid being exposed to the imbalance as it is too late to rebalance its portfolio via the ID market which is closed. Under an HM setup, even if we can imagine that the local ID market GCT is closer to RT than the XB ID market, the OG's BRP can still rebalance its forecasted imbalance by activating flexibility in its own portfolio located in the very same HM BZ but located onshore[39].

This netting solves the financial exposure to the imbalance price for the OG's BRP but not the imbalanced situation in the offshore hub. This is because the imbalance has not been accommodated through a modification of the setpoint on the MINE or the IC like it would have been the case should the ID market be used under an OBZ setup.

Eventually, this imbalance will have to be managed by the TSO using the EU BAL platform. This will come at a cost for the society that the OG's BRP will not have to bear as its portfolio is balanced. One solution could be that the HM TSO restricts any imbalance netting possibility for the OG's BRP. However, this would pose serious issues in terms of discrimination between onshore and offshore BRPs. This challenge should be further elaborated.

For the **OBZ setup**, some challenge arises when it comes to the **determination of the imbalance price**. Following the Art 6.6 E-Reg, an imbalance settlement price should be calculated especially for the OBZ. The balancing bids activated to maintain the balance in the OBZ are mainly activated across BZ via the EU platforms. Those EU platforms give a marginal price (CBMP) for the remuneration of the balancing energy to the BSPs but do not calculate the imbalance settlement price which remains a national prerogative[40]. We see two approaches to tackle this challenge.

1. The OG's BRP is exposed to the imbalance settlement price of the onshore TSO towards which there is no congestion during the balancing timeframe (still to be determined based on the EU BAL platform). In other words, the imbalance settlement price calculation to be applied to its imbalance volume would be that of the TSO having the same CBMP for BAL energy bids. This option can be challenging for the OG, as for the same imbalance volume, it could be settled against two different imbalance settlement prices as a function of the direction of the congestion. This allocation would only be known as ex-post. Moreover, this would require a strong inter-TSO compensation scheme to ensure that the imbalance management process can be self-financed.
2. The OG's BRP is exposed to a specific OBZ Imbalance settlement price which is not based on the imbalance settlement price calculation of neighbouring BZ but only based on the marginal balancing price(s) that are incurred by the TSO in charge of the OBZ's balance.

Notwithstanding the market arrangement, Eurelectric also highlights the fact that imbalances by OG are most likely to impact the balance of only one onshore bidding zone (e.g.: the one for which the connection is uncongested). When OG represents significant volumes, the respective TSOs will need to consider corresponding risks in terms of sizing their balancing reserves. This might prove highly challenging, as in most cases reserve needs are to be determined ahead of the nomination of CZ exchanges (which takes place after the SDAC).

[39] Following Art 6.6.2 E-Reg
[40] Some TSOs are applying the marginal of the marginal concept, some a weighted average price, some other add an extra component to it for various purposes.

Distributive effect

The distributive effect has been explained in the section Day-Ahead Capacity Allocation and showed in the numerical examples (more details also in the annexes).

In the **HM setup**, since the OG is having unconstrained access to its home market, there is no risk of price decoupling towards its home BZ. The MINE is likely to be a regulated transmission asset as no revenue from congestion rent can be expected.

The structure of congestion rents captured by the IC owner differs from the HM-EXEM to the HM-COMP setup. In the first case, the lower MACZT on the MINE will allow less allocated volume on the IC but will favour price decoupling between both onshore BZ. In the second case, the MACZT of at least 70% on the MINE will allow more flow on the IC but will contribute to the price coupling of both onshore BZ. Based on that and the impact of network topology, energy mix etc. it is not possible to determine which one is better off.

In any way, Eurelectric does not see any need to adapt the current legal framework, notably related to (the use of) market and congestion revenues in an HM setup.

In contrast, in the **OBZ setup,** more of the hybrid project's total economic value is likely to take the form of congestion incomes. As shown in the numerical examples of the section Day Ahead Capacity Allocation, the implied reduction in OG revenues resulting from the OBZ setup is not lost in an economic sense but rather transferred to the IC owners[41] in the form of congestion income. This implies that a redistribution mechanism could be developed to undo the negative impact on OG revenues from the introduction of an OBZ, ensuring financial incentives are present to support investments in OG, also under an OBZ setup.

However, it should also be clear that if the **OG pays for (part of) the IC[42], it is entitled to get part of the congestion rent, pro-rata of its financial contribution to the investment in the transmission asset and independently of the effective OG production**. The pro-rata ratio would indeed apply to all nominated cross-zonal trades generating congestion rent on the IC. This would also apply independently of the choice of market arrangement. However, if applied together with a redistribution scheme, it should not result in undue windfall profit.

In the figure below, one can observe the OBZ price as a function of the prices in the onshore BZ A and B (based on the offshore hybrid project example used in this paper). OBZ price will always get the price of the uncongested zone it is connected to. As long as the OG production can be exported via both ICs, **the OBZ price will always be equal to the lowest price of the onshore BZs**. It should be noted that the OG **is also exposed to a higher risk of lower prices** given the fact the price in an OBZ is related to the availability of CZ capacity which might be impacted by congestion on internal onshore network elements (internal congestion are then "pushed" to the border of a BZ preventing OG to export all of its production, eventually pushing the prices in the OBZ to zero as shown on the graph). This risk is highly dependent on the offshore grid's topology (the degree of meshing) as it will determine the ability of offshore hybrid assets to export OG production without being congested.

[41] This can also be an issue for transmission asset developers, if the congestion rent is mainly captured by another TSO involved in the offshore hybrid transmission infrastructure (the one making available the least CZ capacity).
[42] Either because it is considered to be their feed-in line subject to connection charges, or because they own the IC in the frame of a merchant joint venture for generation and transmission assets

One can also observe the congestion rent generated by the allocation of IC's capacities and the spread between BZ prices. In the period 1, 1' and 1", the congestion rent is captured by the IC owner between BZ A and the OBZ while in the period 2, by the IC owner between BZ B and the OBZ. In period 3, the sum of MACZT on the ICs is not sufficient to export all OG production, leading price of zero in the OBZ.

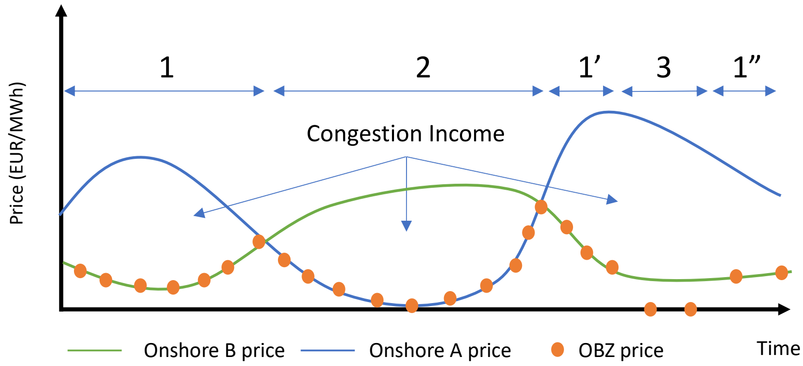


Figure 12 Illustration of the market prices in the OBZ compared to those of the neighbouring onshore BZ

In the following a couple of options are sketched to address the financial risks an OG can face in an OBZ setup (A) application of a direct price support scheme, (B) redistribution of congestion rent (ex-post or ex-ante) or (C) the set-up of a joint venture (IC+OG) project.

In particular, Eurelectric explains and analyses the hedging quality and the legal barriers of those different schemes aiming at reducing the impact of the distributive effect on the OG developers.

A. Direct price support scheme

The idea is to consider a direct price support scheme (potentially organized via tenders by the relevant Member States[43]) that would not require to change elements of the current market design by ensuring revenues from the OG are only composed of market revenues complemented by the support and so are independent of the congestion rent collected by IC owners. For example, this could take the form of a two-sided contract for difference (CfD), a strike price is determined in a competitive process. As shown in the graph below, when the OBZ price is under the strike price, the OG receives the difference or has to pay back the difference when the price differential is in the other direction. The price risk for the OG completely disappears. Only the volume risk linked to the inherent variability of the OG production remains. But it has to be noted that this volume risk is present anyway. This makes that the direct price support scheme has the best hedging quality for an OG developer.

Under this scheme, the IC owner keeps the entire congestion rent which can eventually be used by the TSO to further reduce the grid tariff[44]. On the other hand, additional tax/levy would be needed to finance the direct support scheme OG, which is to be eventually paid by the taxpayer (or directly by electricity consumers in some MS). The price risk introduced by OBZ is then borne by the counterparty to the support scheme.

[43] Note that tenders and support schemes, traditional organized by a single MS, could be organized commonly by two or more MS, especially in the context of OBZ.
[44] This reduction of grid tariff is however not applicable when considering merchant IC investments

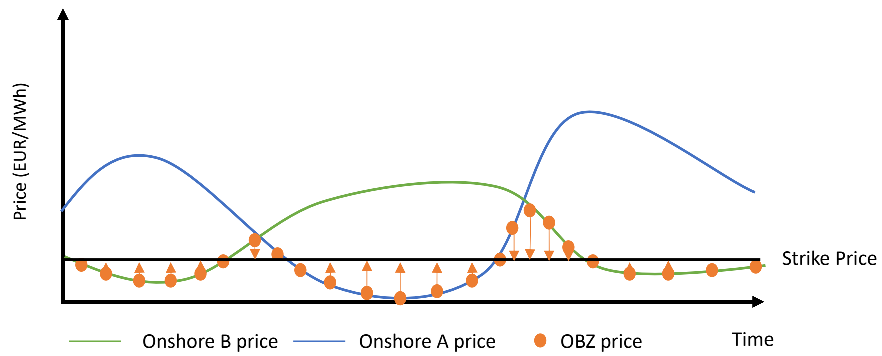


Figure 13 Illustration of the price get by OG under an OBZ setup with a classical support scheme

However, such a support scheme also has its drawbacks. Today, the trend shows that support schemes are granted for a limited period so that after this period, the OG is exposed (again) to lower captured prices in its OBZ. Taking that into account when bidding for the support scheme tender, the strike prices for OG in OBZ will tend to increase. Moreover, the nationality of the taxpayer paying the higher support might not always be one of the grid users that benefits from a reduction of the grid tariff resulting from the additional congestion rent earned by regulated IC owners (TSOs). Hence the divergence in costs and benefits between MS connecting to an offshore hub could be an inherent issue of this approach.

B. Redistribution of the congestion rent[45]

When a **redistribution scheme** is considered, the congestion rent collected by the IC owner is reduced by the amount the OG gets on top of its market revenues, according to its production and use of the transmission asset. This can eventually erase any difference between the total revenue for an OG in an HM (only market revenue) or an OBZ setup (market revenue + redistribution of the congestion rent). Compared to the previous approach, this also means that a smaller budget can be deducted from the grid tariff[46] but, at the same time, there will be no extra taxes/levies on electricity consumers to address the OGs lower market revenues in case of OBZ setup.

The advantage of redistribution of the congestion rent is its stability as it would be embedded in a new, enduring regulatory framework, enabling IC owner to have a broader – but well defined - use of the collected congestion rent, under certain circumstances. This would be systematically applied and without a limitation in time what provides certainty for the OG developer, exposing the developer only to the same risks that other generators (e.g. onshore, or radially connected OG) are exposed to.

The most obvious regulatory challenge to allow the redistribution of the congestion rent concerns Article 19 of Regulation (EU) 2019/943. This article effectively requires that all congestion income be earmarked for securing or expanding cross-zonal capacity. If these objectives are adequately fulfilled, congestion incomes may alternatively be returned to network users through lower tariffs. This barrier impedes the TSOs to redistribute the income from the congestion rent to other investors although this could ensure the viability of the project for the OG developer, despite being located in an OBZ. In theory, this barrier could be overcome by linking the rules for distribution of congestion rent to the definition of a hybrid offshore asset. This would mean creating an alternative set of rules or regulatory

[45] The question whether the redistribution of Congestion Rent can be considered as a Support scheme as defined in RED II is out of scope of this paper.
[46] This reduction of grid tariff is however not applicable when considering merchant IC investments

framework for those specific assets. This framework would, among others, define the rules on how to redistribute the congestion rent while keeping sufficient room in the text to allow different offshore hybrid project structures to be considered.

There are several options for redistributing incomes from the congestion rent which have a different level of hedging quality. Obviously, those options have an impact on the revenue of IC owners. Two main groups are presented: the ex-ante and the ex-post approaches, in relation to the DA timeframe. This timeframe is chosen as a reference because by then, the IC owner gets a clear view of its revenues (selling of DA capacity and potential remuneration of LTTR owners added to the revenues from the selling of LTTR) and the OG has a much more precise forecast of its production.

1. <u>Ex-post redistribution of the congestion revenue collected at DA timeframe</u>

Under this option, the redistribution is based on the incomes of the DA congestion rent. Two approaches are presented: *HM* and *High price BZ look-alike*. Those approaches require the IC owner to be able to make different use of the congestion rent than the one prescribed in Art 19 E-Reg as part of it will be redistributed to a third party.

- HM look-alike:
  A CfD between the OG and the IC owner is signed. It is based on the DA market price of one specific onshore BZ (B in the example below). The IC owner and the OG agree to transfer the price spread between the OBZ and the onshore BZ multiplied by the OG energy sold at DA timeframe (the volume seen from DA is completely hedged then but the imbalance risk remains as any onshore generation). The price risk is hedged against the onshore BZ price. It has to be noted that the onshore BZ price is still variable so that the hedging does not result in a flat price from OG's perspective as in the direct price support scheme.

  In terms of financial flows for the OG, it is the same result as if it would operate under the HM setup. The consequence of this approach is that the congestion income collected by the IC owner will eventually be reduced and this reduction is proportional to the actual OG produced energy. This can undermine the appetite for merchant transmission investment in offshore hybrid assets, depending on the connection charge structure paid by the OG.

  This is shown on the graph below. The OG gets the price spread between the OBZ and the selected onshore BZ multiplied by its sold production (which is only a part of the total allocated flow on the IC – see figure 16). The remaining part of the congestion rent (the one generated by the same price spread but multiplied by the commercial flow not implying OG's bid) would be kept by the IC owner.

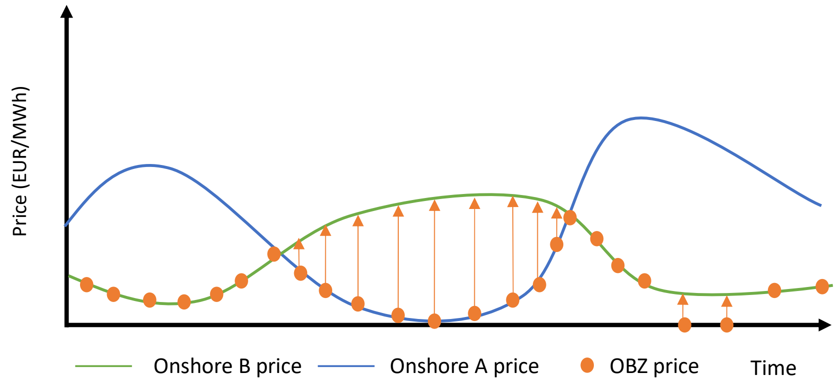


Figure 14 Illustration of the price get by OG in an OBZ set up with an "HM-like" redistribution scheme

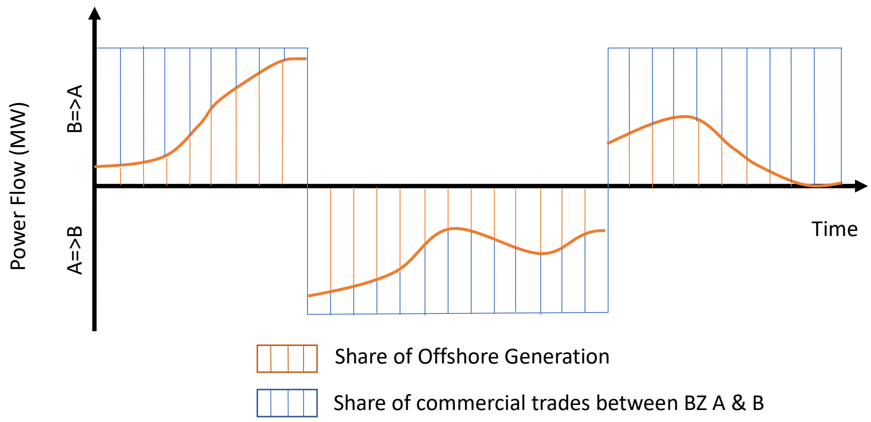


Figure 14 Sharing ratio of OG production compared to total commercial flow to determine the redistribution

As explained previously, even if the OG is not exposed to the OBZ price anymore, it remains exposed to the DA market price of the selected onshore BZ which can also be volatile. The revenue stream is therefore not guaranteed. As a consequence, the investment is not guaranteed either. One can imagine the combination of this option with a support scheme. We can expect that the strike price would be lower because part of the price risk is already hedged via the unconstrained access to the onshore BZ price. The drawbacks identified for the direct price support scheme would hence be less acute.

- High price BZ look-alike:
  In this approach, the OG is allowed to directly benefit from part of the congestion rent independently of the direction of the flow, at the level of its sold energy. The difference with the HM look-alike approach is that the OG will see the high price on each market time unit.

  The OG gets the price of the onshore BZ to which the offshore generation is transported (the highest priced zone to which there is capacity). The consequence is that both ICs between the OBZ and each onshore BZ receive less congestion rent, and this reduction is proportional to the OG sold energy and depends on the flow direction between both onshore BZ. The OG remains exposed to the price risk related to the volatility of the DA market price of the onshore BZs but is ensured to get the highest one (see graph below). The congestion revenue captured by the interconnector owner is then limited to the traded volumes between onshore markets (I.e. excluding the offshore generation), see figure 12.

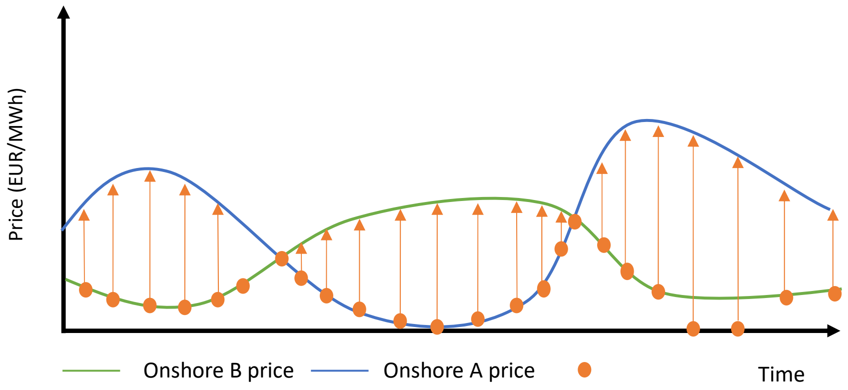


Figure 15 Illustration of the price get by OG in an OBZ set up with a "High price BZ - like" redistribution scheme

2. <u>Ex-ante redistribution via sharing of FTR (revenue) at forward timeframe</u>

Under this option, the redistribution is less direct and is based on the sharing of FTR or the revenue from FTR auctions. Two approaches are presented: pre-allocated FTRs and the allocation of Auction Revenue Rights.

- Pre-allocated FTRs:
  Financial Transmission Rights are allocated on preferential conditions – to be determined - to OG during the Long-Term Transmission Right Allocation process. The price risk is covered because FTR can be resold at the DA stage and at the price of the spread between the OBZ and the onshore BZ. However, there is an additional volume risk as FTR are allocated before the actual OG output is known. The challenge will then be to define the volume of the FTR option to allocate to the OG. A further challenge is how to reconcile the typical length of FTR options sold in the market with the economic lifetime of offshore generation assets.

  It has to be noted that FTR can be allocated in only one or in both directions, which might complexify the process. Moreover, the allocation of FTR may be free or may require some payment from the OG to the IC owner (potentially following a competitive process), which further complicates the design and might deteriorate the hedge quality regarding the prices.

  This approach touches upon an existing forward transmission right market with established rules and processes. Therefore, it will not be easier to implement it than any other options (such as the redistribution of the congestion rent collected at the DA stage) as it will require changes in terms of the regulation (notably FCA GL) and operation. Especially when it comes to the *preferential* aspect of the FTR allocation.

- Allocation of auction revenue:
  In this approach, the IC owner sells FTRs in an (or multiple) auctions (s) as this is done on the majority of EU BZ borders and the OG receives a share of the revenue resulting from the auction(s). Contrary to the HM look-alike and Pre-allocated FTRs cases, the approach will not reflect the actual price spread but just a long-term expectation of it and hence the OG remains exposed to short-term price risk. However, the OG can also participate in the FTR auction(s) and could turn its revenues from FTR auctions into FTRs, thereby regaining a price hedge. Auction revenue rights are not applied in the EU today and would require a change to the regulatory framework.

We note that any of these redistribution options (ex-ante and ex-post) relies on significant changes of the E-Regulation applying to the European electricity system.

		Price hedge quality	Volume hedge quality
Direct price support scheme		++	+
Ex-post redistribution	HM-alike	+	+
	High price alike	+	+
Ex-ante redistribution	Pre-allocated FTR	+	-
	Allocation of auction revenue	0	-

Table 5 Qualitative assessment of the different option wrt the quality of the price and volume hedges

C. Joint ownership for a single project

A joint venture between transmission and generation developers is set up. The duality of the offshore hybrid asset would be reflected in the sharing of benefits but also of costs. The potential need and the rules for the redistribution would be internalized in the joint venture. This would enable generation and transmission developers to consider project costs and revenues in aggregate. However and similarly to the ex-ante redistribution scheme, the IC owner should have to possibility to share part of its congestion rent with a third party (within the joint venture though) requiring a regulatory change.

Moreover, there might be some legal challenges in terms of unbundling that should be clarified. This joint venture option is promising but will probably not be applied to all offshore hybrid projects so that the previously described options should still be considered anyway.

Long-term Scalability and Adaptability

To reach the goal of 300 GW of installed offshore wind capacity by 2050 the market design should facilitate the gradual expansion of OG, consumption, and transmission efficiently. In this chapter, we outline how the choice of market design arrangements would have an impact in the context of scalability and adaptability. Scalability can be defined as the property of a system to create value and to remain robust when adding additional assets, while adaptability is the ability or willingness to change to suit different conditions.

In general, it is important that the market design provides market participants with reasonable regulatory certainty in their investments. This implies that regulatory changes with a significant impact on the profitability of an investment that investors could not foresee or have no control over should be avoided. For this reason, it is required that the market arrangement to which the asset will be subject to is clear when the investment decision is made.

We note that changes in the offshore hybrid asset structure (e.g. addition of new IC) or in the offshore generation or consumption environment will, without any doubt, impact the market conditions and related revenues for existing assets (which have no means of action on these changes). However, the choice of market arrangements will determine to what degree those changes will impact existing assets. It seems clear that an **HM setup** will provide more certainty to the OG as its access to its home BZ (and the related market dynamics, prices, depth and liquidity) will be guaranteed anyway. On the contrary, under an **OBZ setup** and especially in the first phases of the development of an offshore grid, each change will importantly impact the OG's revenues. The metric representing the relative capacity of the transmission asset compared to the capacity of the OG asset determines to what extend an OG is exposed to changes in the offshore grid. Therefore, progressively, as the offshore grid gets meshed and access to more BZ is ensured, the impact of each change will decrease.

In the following section, we outline the effect the market design arrangements have on pricing signals for investment via two examples.

First, let's consider a case where two onshore bidding zones are connected by an interconnector, with an OG in an **HM setup** connected to BZ A. BZ A is generally the high-price area, BZ B is generally the low-price area. An investor is considering investing in an additional OG that is to be connected to BZ A in the same way as the existing wind farm. In the existing configuration, the MINE connecting the OG to BZ A is generally congested because of either OG or import from BZ B. With this setup, the investor sees the price of BZ A, while the marginal value of the additional production consumed is more likely to approach the price in BZ B. In this case, the distortion of the price signals in DA (by giving unconstrained access to BZ A market even if the physics cannot handle it) might result in wrong incentives for the investors in new generation/consumption asset from a system point of view. However, from an investor point of view, the HM setup gives a stronger investment incentive, because it leads to higher and more stable revenue, less dependent on changes in the system setup than in the OBZ solution.

Figure 16 Additional OG in an existing Offshore Hybrid Project under HM and OBZ setup

Second, let's consider a case where the OG is in an **OBZ setup**, the price in this OBZ is likely to be closer to the low price BZ B, and thus reflects the marginal value of added offshore production. If and when the additional offshore production is added it might cause both interconnectors from the OBZ to BZ A and BZ B to generally become congested, and the price in the OBZ is likely to drop even further. This illustrates that while the OBZ might provide accurate energy and interconnector capacity pricing signals, there is a need to provide investors with certainty that interconnector capacity will be established in light of a CBA to incentivize investments in offshore production capacity under an OBZ market arrangement. This also illustrates that the potential aspect of moving an offshore production asset from an HM to an OBZ setup would constitute a significant regulatory uncertainty.

It should be noted that the reasonings above are based on pure market price signals; any form of support scheme (classical or trough redistribution of congestion rent) modifies these signals and may change investment incentives. In that case, the comparison between both setups should be viewed in light of required support or redistribution schemes.

Let's now consider the possibility of connecting a load to the hub where an OG is located. We still assume that the MINE connecting the hub to BZ A is generally congested, due to import from BZ B and offshore wind generation at the hub in both market setups. In the **HM setup**, we expect that the price at the hub will be equal to that of BZ A. In the **OBZ setup**, the price at the hub is expected to be more often equal to that of BZ B. If we assume that the planned consumption is only financially viable from an investor point of view up to a price point somewhere in the range between the prices in BZ B and BZ A, the proposed consumption will not be established at the offshore hub in the HM setup[47]. However, it could be established at the offshore hub in an OBZ setup. It would be efficient to establish the load at the hub from a system point of view.

Figure 17 Additional consumption asset in an existing Offshore Hybrid Project under HM and OBZ setup

OBZ setup can contribute to providing suited economic locational signals for marginal investment behaviour in the context of a complex offshore grid with production and loads. However, as already pointed out, energy price is not the only component of an economic signal, and the HM solution ranks better in terms of robustness from an OG investor point of view, which could favour the achievement of the political offshore development objectives of the EC strategy.

Summary of the discussion

The following table summarizes the challenges identified for the three market arrangements under consideration over each market timeframes.

	HM-COMP	HM-EXEM	OBZ
Forward	No issue as there is unconstrained access to HM forward market and related liquidity.		The liquidity in OBZ will be limited putting at risk any hedging strategy. The interplay between FTR and redistribution schemes must be duly considered.
DA Capacity Calculation	OG forecast has no direct impact on CZ capacity available for commercial trades potentially leading to RDCT after DA market.	TSOs has to forecast OG production as DA CC is their prerogative. TSOs might under/over-estimate to	CZ capacity available for commercial trades is calculated independently of the OG forecast.

[47] This reasoning assumes that all other things are equal, which notably implies that only the energy price conveys a locational signal. This is not necessarily the case, since connection charges – known at the time of the investment – can also be modulated depending on the connection point.

<table>
<tr><th></th><th>HM-COMP</th><th>HM-EXEM</th><th>OBZ</th></tr>
<tr><td></td><td></td><td>maximize their incomes from the congestion rent or minimize its RDCT costs. The role of RCC is important.</td><td></td></tr>
<tr><td rowspan="2">DA Capacity Allocation</td><td>Over-allocation of the scarce IC capacity because of the 70 % rule leads to high RDCT volume.</td><td></td><td rowspan="2">• With no or limited after-market actions, the price signal is accurate however price indeterminacy situation can occur for which clear rules should be developed ex-ante.
• Uncertainty in terms of CZ capacity available between 70% and 100 % (depending on TSOs calculation).
• Higher risk of low prices, should the transmission capacity be limited to export OG production
• Extra BZ adds pressure on the performance of the Market Coupling algorithm</td></tr>
<tr><td colspan="2">Negative Price in only one onshore BZ may lead to an inefficient dispatch and hence lower global social-economic welfare</td></tr>
<tr><td>Scheduling</td><td colspan="2">The discrepancy between DA TSO's forecast and BRP's forecast at scheduling timeframe can unveil unused CZ capacity for the DA MC or cause an overload on the MINE requiring RDCT</td><td>OG schedule not important for IC setpoint. Change in OG portfolio to be adjusted via ID by OG. A shift in responsibility from TSOs to OG's BRP and shift in terms of costs.</td></tr>
<tr><td>ID Capacity Calculation</td><td colspan="2">• Given the assumption that the Art 16 E-Reg only applies to DA capacities (ACER guidance), HM-COMP doesn't differ from HM-EXEM in terms of ID CC&A. Similar challenges as for HM-EXEM in DA CC arise in ID.
• RDCT applied in ID timeframe would be required</td><td>TSOs do not have to consider OG's production forecast during the ID CC process as they have no priority access to the IC. The ID capacity will be the leftovers of the DA capacity allocation, at minimum, or the result of an ID recalculation.</td></tr>
<tr><td>ID Capacity Allocation</td><td colspan="2">OG can freely trade within its HM BZ, where the copper plate assumption is of application</td><td>OG can freely trade within its OBZ and across the border if there is CZ capacity. Liquidity might be limited in the OBZ as there would be a high concentration of similar market participants, leading to potential volatile prices in the ID timeframe.</td></tr>
</table>

	HM-COMP	HM-EXEM	OBZ
Congestion Management	Table 4 Use of congestion management under the different market arrangements		
Balancing	• The OG's BRP is only exposed to the HM BZ imbalance settlement price. • Use of EU BAL platforms should be facilitated to accommodate the offshore hub without defining a new BZ.		• TSO cooperation needed for the determination of the imbalance settlement price in the OBZ. • Use of EU BAL platforms is needed and should not pose any issues.
Distributive effect	The OG gets the price of its HM as any onshore generator.		Compared to HM, more of the hybrid project's total economic value is likely to be earned directly as congestion income by IC owners. Redistribution of congestion rent might be needed since there is a reduction in generators' revenue. This could be combined with support schemes.
Long-term scalability and Adaptability	• Potential distortion of price signals in DA, due to activation of RD as a consequence of DA allocation of a XB capacity not reflecting actual network capabilities. This might result in wrong locational signals for future additional investments in OG. • Stronger and more robust long term investment signal from an OG investor's point of view, since future revenues are higher on average and less sensitive to changes in the system physical setup.	The DA price the OG is exposed to does not provide a price signal that reflects network constraints on MINEs.	• OBZ setup can provide suited economic signals for marginal investment behaviour in the context of a complex offshore grid with production and loads • OG are more exposed to additional transmission/generation/consumption asset given the impact on the OBZ price.

	HM-COMP	HM-EXEM	OBZ
	The DA energy price signal is not the only tool to incentivize investments (in generation or consumption asset). Grid connection fees and, if applicable, support schemes also play an important role.		

Table 6 Summary of the issue and challenges identified for HM-COMP, HM-EXEM and OBZ setup under the different market timeframes

E. Conclusion and Recommendations on the way forward

Eurelectric assessed different market arrangements and clarified consequences of the application of each of them on the different market timeframes in light of the following principles: efficiency of dispatch, minimization of the distortion of price signals, technological neutrality of the market design, needed the stability of BZ configuration and foreseeability of revenues for market players.

Based on this assessment, **Eurelectric cannot express a clear preference** in favour of one market arrangement or even an order of preference. Eurelectric observes in its assessment that a lot of topics are not detailed yet and there is limited experience in the development of hybrid projects. **This prevents taking any clear position.**

Therefore, Eurelectric **calls the EU legislators to further detail grey areas identified in this discussion paper** and this, especially, for OBZ and HM-EXEM which require amendments of the current regulation. At first glance, HM-COMP setup does not require a change in the regulation but should also be included in the discussion on a level playing field. In that framework, **Eurelectric calls for an EU-wide debate with the involved stakeholders to clarify the regulatory framework(s)** to be applied to offshore hybrid projects (incl. clear definitions) as many challenges related to the proper integration in the electricity markets were identified under all market arrangements. Eurelectric's present assessment contributes to this debate by providing for each market arrangement a list of requirements to be met before implementing any of them.

In any case, and this is valid for any market arrangement, **the financial incentives should be sufficiently clear to develop the (offshore) transmission and generation capacities.** These are needed to meet the EU net-zero target by 2050 and the intermediate milestones which are also supported by Eurelectric. The potential need for classical support (via the government) or redistribution (via IC owners) schemes depends on the chosen market arrangement but also the physical configuration of the Offshore Hybrid Project and future offshore grid developments. **Eurelectric supports the development of a legal framework that would facilitate such schemes if needed.** However, they should not lead to a distortion of the target model which is the basis for the whole European market design. In any case, given the broad range of projects' structure and expected ROI, competitive tenders should be promoted.

Eurelectric also identifies topics that are hardly developed for the time being but that should be duly analyzed to reach the EC ambition in terms of Offshore energy.

The concomitant development of offshore transmission capacity and generation capacity must be efficient while maximizing the social-economic welfare and making sure that market participants are not exposed to a risk they cannot take. Therefore, **coordination and cooperation amongst all offshore stakeholders must be ensured via existing or to be created, coordination bodies**. The role of TEN-E and TYNDP regarding offshore network development planning should be clarified. The development of a hybrid project including the **sizing of the network infrastructure, the sharing of the associated costs, as well as the possibility of anticipatory grid investments**, should be discussed.

The possible **ownership structure and operation** of the IC/MINE, in both OBZ or HM setups should also be tackled considering merchant, exempted or regulated ownership, possibly all active in the same Offshore Hybrid Project. Would an ISO model make sense? Moreover, the possible joint ownership of IC/MINE and OG should be considered, as this approach might favour the development of offshore hybrid projects by decreasing the financial risks for the stakeholders.

Should a new offshore BZ be created, **a very important question is then how are the responsibilities shared amongst the onshore TSOs, NRAs and RCCs**? What would be the future role of RCC, notably when considering an offshore meshed grid where numerous TSOs are active?

When it comes to the **evolution of the offshore grid and OG**, how should the impact on revenue streams for stakeholders be tackled? The following cases can be taken into consideration: An Offshore Hybrid Project planned to be built on existing OG or on an existing interconnector (that planned it or not).

Eurelectric also identifies challenges related to the **interplay between the tendency of harmonization on the EU level and the need to keep national particularities**. What will be the impact of national tariffs including connection charges to foster investment at the right place? Should we consider specific network tariffs for the OBZ? What is the impact of the (potential) mechanism to redistribute congestion rents and how does it apply onshore? How a bidding zone review process (being EU-wide or Regional) would impact the market arrangement chosen (shift from OBZ to HM and vice-versa). And finally, how to include the cooperation with third countries?

The elements mentioned here above show that a debate should take place amongst all stakeholders to co-create the necessary framework. **Eurelectric hereby shows its high interest to participate** and encourage the legislator to take into account the elements described in this discussion paper.

Annexe

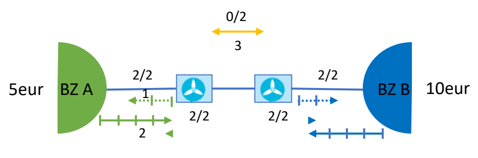
DA Capacity Allocation: numerical examples

The examples here below are more developed than the ones at the core of this discussion paper. All the steps related to the capacity calculation and (pre-) allocation are described.

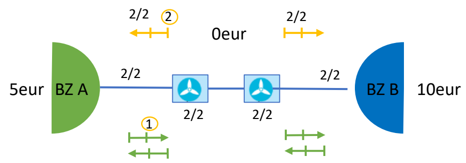
Distributive effect

This effect is illustrated in the figure below. **One can observe that market revenue the OG gets under the HM-EXEM setup is fully transferred as congestion rent** for the IC owner under an OBZ setup.

HM-EXEM



OBZ



1 During the CC process, OG forecasted production has unconstrained access to the HM BZ.
2 Based on 1, TSOs calculate the XB capacity available for XB trades.
3 Market coupling results in no XB exchange because of zero MINE capacity, resulting in no commercial exchanges on the IC.

1 TSOs calculate XB capacity available for XB trades
2 Market coupling results in XB exchanges

Home Market			Offshore Bidding Zone			Effect
Congestion Rent (CR)	OG revenue	Total income	Congestion Rent	OG revenue	Total income	• Same dispatch = same generation costs • Same Social Economic Welfare • **Redistribution of income** between IC and OG owner
CR_A/B= 0	OG_A=2*5=10 OG_B=2*10=20	**CR= 0** **OG=30**	CR_A/H=2*5=10 CR_H/B=2*10=20	OG=4*0=0	**CR=30** **OG=0**	

OG pre-allocated physical flow

Capacity available for XB trades (prior to the market coupling)

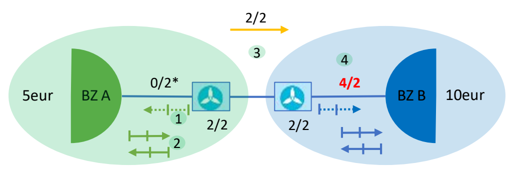
XB trades

x/y Allocated transmission capacity or OG output / Total transmission Capacity or OG capacity

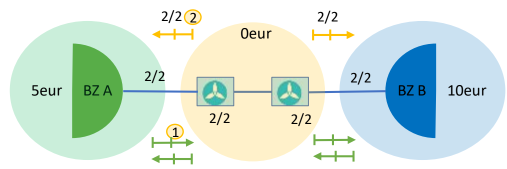
Figure 18 Numerical example comparing HM-EXEM and OBZ setup wrt Congestion rent and Market revenues

Distortion of DA price signal

HM-COMP



OBZ



1. During the CC process, OG forecasted production has unconstrained access to the HM BZ
2. TSOs calculate the XB capacity available for XB trades, overlooking 1
3. Market coupling results in XB exchange from the BZ_A to BZ_B leading to an overload between OG_B and BZ B (caused by the XB flows and the OG_B production)
4. BZ_B's TSO is required to perform RDCT (either internally with OG_B or XB with BZ_A)

1. TSOs calculate XB capacity available for XB trades
2. Market coupling results in XB exchanges

Home Market-B			Offshore Bidding Zone			Effect
Congestion Rent (CR)	OG revenue	Total	Congestion Rent	OG revenue	Total	• CZ capacity allocated DA **does not reflect the technical feasibility**
CR_A/B= 2*5=10 * (2-2)=0	OG_A=2*5=10 OG_B=2*10=20	**CR= 10** **OG=30** **+ RDCT cost**	CR_A/H=2*5=10 CR_H/B=2*10=20	OG=4*0=0	**CR=30** **OG=0**	• **Distortion of DA price signal** with the HM setup (unfeasible exchanges artificially leads to higher price in BZ_A and lower prices in BZ_B**) • **Less efficient dispatch** (depending on the RDCT management)

* *This cannot be observed in the numerical examples as we assumed inelastic demand

Wind pre-allocated physical flow

Capacity available for XB trades (prior to the market coupling)

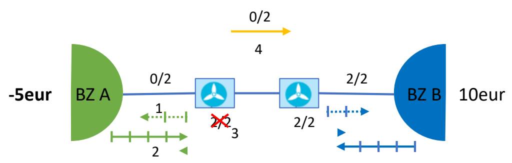
XB physical trades

x/y Allocated transmission capacity or OG output/ Total transmission Capacity or OG capacity

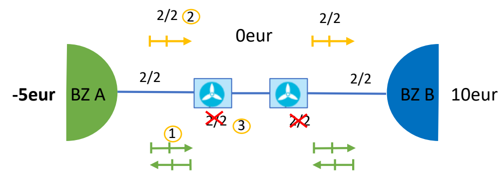
Figure 19 Numerical example comparing HM-COMP and OBZ setup with regards to the distortion of price signal in DA

Impact of negative prices

HM-EXEM



OBZ



1. During the CC process, OG forecasted production has unconstrained access to the HM BZ
2. Based on 1, TSOs calculate the XB capacity available for XB trades
3. OG in BZ_A is not dispatched because of negative prices in BZ_A
4. OG in BZ_B is dispatched instead of cheapest import from BZ_A

1. TSOs calculate XB capacity available for XB trades
2. Market coupling results in XB exchange
3. OG is not dispatched because of the local price

Home Market			Offshore Bidding Zone			Effect
Congestion Rent (CR)	OG revenue	Total income	Congestion Rent	OG revenue	Total	• **Different** dispatch
CR_A/B= 0*15=0	OG_A=0*0=0 OG_B=2*10=20	**CR= 0** **OG=20**	CR_A/H=2*5=10 CR_H/B=2*10=20	OG=0*0=0	**CR=30** **OG=0**	• **Different** overall generation costs: 2 onshore units @–5eur/MWh dispatched with the OBZ Vs 2 OG units @0eur/MWh with HM • Thus **higher welfare in the OBZ than in HM-EXEM**

OG pre-allocated physical flow

Capacity available for XB trades (prior to the market coupling)

XB physical trades

Not Dispatched

x/y Allocated transmission capacity or OG output / Total transmission Capacity or OG capacity

Figure 20 Numerical example comparing HM-EXEM and OBZ setup wrt Congestion rent and Market revenues – in case of negative prices

The rationale supporting each market arrangement

After assessing the three market arrangements in the different market timeframes, Eurelectric finds that there are pros and cons for each market arrangement. We also find ways to overcome the disadvantages associated with each market arrangement. For each market arrangement, the following table summarizes the disadvantages and presents a way forward on how to overcome these challenges. This should not be considered as a formal Eurelectric position but rather as ideas to be considered by the legislator.

	HM-EXEM (review or derogation) ensuring efficient market dispatch through the Market Coupling algorithm
1.1	EC published the ORES, planning 300GW of offshore energy by 2050. This is a political will that Eurelectric supports in the framework of the net-zero.
1.2	CEP states that 70% of transmission capacity should be available for CZ trades to avoid undue discrimination between internal and CZ trades.
1.3	**Eurelectric does not support this rule as efficiency cannot be reached with an ex-ante defined threshold.** This threshold should be defined border per border.
1.4	Hybrid projects are the perfect example that 70% does not make sense everywhere. In order to respect the 70%, massive volumes of RDCT would have to be applied, leading to higher generation cost and lower SEW.
1.5	EC is correctly observing the previous point and proposes to implement OBZ where 70% would be easily respected, by design.
1.5.1	However, it has been shown that OBZ setup does not provide the same market revenue as in HM because of the distributive effect transforming market revenues for the offshore hybrid generator to congestion rent for IC owner
1.5.2	Therefore, EC is proposing to amend Art 19 for the use of congestion income in order to redistribute part of it to the OG.
1.6	All that for accommodating the 70% rule.
1.8	As a counterproposal and building upon 1.3, either **derogation** (not the preferred option) or **special regulations** (e.g. for hybrid projects or more generally for HVDC) should be granted/put in place for the hybrid project. This would mean that the HM setup could be applied without adapting the Art 19 CEP.
1.9	However, it has been shown that HM setup can trigger inefficient dispatch situations and/or can distort the DA energy price signal:
1.9.1	Inefficient dispatch situations are triggered by onshore prices below the marginal production cost of OG. When considering zero marginal cost, this means that those situations are triggered when the other BZ has negative prices. See 1.10.2 to solve that.
1.9.1a	Negative prices can be due to badly designed support schemes. State Aid GL is supposed to solve that by preventing getting support when prices are negative.
1.9.1b	Negative prices can be due to incompressibility issues leading to Must Run for ancillary services or inflexible assets.
1.9.4	Potential distortion of DA price signal may take place when HM is made Art 16.8 compliant, requiring RDCT to be activated as corrective measures, ex-post.
1.10	Taking into account the previous points, Eurelectric proposes the following approach

1.10.1	The commercial capacity would be the physical capacity minus the OG production forecast (as there is no loop flows nor unscheduled allocated flows on HVDC).
1.10.2	A mechanism should ensure that no inefficient dispatch situation occurs when the marginal cost of OG is greater than the marginal cost of the other BZs. This could be ensured by an economic redispatch from the TSO.
1.10.3	Following 1.10.2, the OG would then undergo a "**forced economical curtailment/redispatch**". Compensation should be potentially considered in case of non-market-based curtailment.
1.10.4	A dedicated regulation for hybrid project needs a clear definition of hybrid projects.

Table 7 Rationale of HM-EXEM set up

	OBZ complying with inflexible Art 16.8, potentially including support schemes to reach EC ambitions
2.1	EC published the ORES, planning 300GW of offshore energy by 2050. This is a political will that Eurelectric supports in the framework of the net-zero.
2.2	Eurelectric strives for market rules that e.g. ensure efficient dispatch, the accuracy of price signals and a level playing field (LPF) amongst market participants
2.3	If the 70% rule is inflexible and cannot be adapted in any way, and as Eurelectric wants to encourage accurate price signals, the OBZ approach is a way forward, potentially with support schemes.
2.4	By the creation of a new OBZ, the argument of LPF between onshore and offshore is not relevant anymore, as the BZ is no longer the same. Another BZ means other market prices (if limited CZ capacity) and this is a known risk.
2.5	However, it has been shown that the OBZ setup does not get the same revenue (+ increased revenue risk) as an onshore generation because of the distributive effect transforming market revenues for the offshore hybrid generator to congestion rent for IC owner.
2.6	This puts at risk any investments in OG under the OBZ setup, breaking the investment chain of potential hybrid projects with positive CBA when considered as one project (transmission + generation).
2.7	This will have an impact on the reaching of the 300GW (or 60GW by 2030) as stated in the ORES. Therefore, the following options exist to cope with the potential lack of profitability for OG under the OBZ setup:
2.7.1	**2.a Joint Ventures** (merchant transmission network + OG developer) are created when projects have positive CBA so that the revenue issues are internalized in the JV. **However not all hybrid projects will be set up in joint venture mode, and this setup may raise questions regarding unbundling requirements**. And this is another barrier to reach the EC ambition. Therefore 2.7.2/3/4 are needed.
2.7.2	**2.b A classical support scheme** is put in place for OG. Is that politically acceptable given the envisaged massive volumes of OG? This allows to avoid the amendment of Art 19 E-Reg but puts the risk on some kind of cross-subsidy between MS.
2.7.3	**2.c A redistribution of the congestion rent/FTR** is put in place, requiring an adaptation of the Art 19 E-Reg/FCA. The redistribution scheme could be the HM-mimic where Congestion rent is shared so that OG sees the HM price (HM is to be defined ex-ante). On top of that, likewise, the previous solution, a compensation for the non-market-based curtailment, in case of negative price in the other BZ, should be foreseen to ensure full LPF with onshore HM generation.

	There will be a price for the OBZ, but this price will not be seen by OG all the time. The adaptation of Art 19/FCA for a hybrid project would require a clear definition of a hybrid project.
2.7.4	2.7.2 could also be coupled with 2.7.3 in order to create a competitive process.

Table 8 Rationale of OBZ set up

	HM-COMP
3.1	EC published the ORES, planning 300GW of offshore energy by 2050. This is a political will that Eurelectric supports in the framework of the net-zero.
3.2	CEP states that 70% of transmission capacity should be available for CZ trades to avoid undue discrimination between internal and CZ trades. Eurelectric does not support this rule in principle, as efficiency cannot be guaranteed with an ex-ante defined threshold, but recognizes that it is now embedded in the European legislation and should be taken as a starting point. Indeed, it doesn't seem realistic nor appropriate to base the development of offshore wind only on derogations (as also stated by the EC).
3.3	Eurelectric cannot exclude cases where OG would be below 30% of the weakest transmission asset. In that case, no derogation would be necessary for the HM solution to ensure that 70% of the physical capacity of transmission assets is offered for cross-zonal exchanges.
3.4	Besides, even if the criterion above is not fulfilled – which means that RD/CT will be needed, potentially to a large extent, to deal with congestions resulting from the DA-allocation – Eurelectric acknowledges that the loss of economic efficiency may not be significant, depending on whether RDCT is performed early enough and with sufficient CZ coordination.
3.5	The impact of the 70% rule on the accuracy of price signals can also be mitigated by speculative behaviour between the DA and the ID/BAL timeframes, which would tend to align the DA prices with the prices reflecting the situation after application of remedial actions by the TSOs. This requires however those market players can anticipate correctly these prices, are allowed to keep an unbalance in the DA timeframe, and that remedial actions are performed in a way that impacts market prices (e.g. CT).
3.6	Considering the elements above, Eurelectric considers that the application of the HM-COMP is not necessarily incompatible with the market design principles it supports.
3.7	The potential inefficiencies of dispatch in case of negative prices remain with this solution, but one should take into account that these situations are expected to be rare, all the more that they are notably due to badly designed RES support schemes, which are expected to be phased out in the future.
3.6	On the other hand, HM-COMP has advantages in terms of alignment with the existing market framework (stability of the current BZ configuration, no need for derogations, level playing field for all assets and technological neutrality).
3.7	It also provides higher revenues for OGs because it avoids transforming market revenues into congestion rent for IC owner, and is robust to changes of the physical offshore setup (e.g. addition of new OG connected to an existing hub).

Table 9 Rationale of HM-COMP setup

Price indeterminacy issue

It has to be noticed that the price could be set at 0 in the OBZ even in case not all interconnectors are simultaneously congested (thus inducing a permanent zero remuneration which would prevent any market-based development of OG), depending on the way the welfare maximization problem is handled by the allocation algorithm. Indeed, given the specific offer curve of offshore wind, a price indeterminacy arises, making it equivalent in terms of global welfare that the OG gets the price of the neighbouring BZ towards which the interconnection capacity is not constrained, and the TSO gets no congestion rent, or that the OG gets 0 and the TSO gets the price difference with the neighbouring BZ as congestion rent (cf. scheme below).

By selecting one solution, the algorithm will define the respective revenues of the interconnector owners (via congestion rent through the price spread) and the OG (via the price definition in the OBZ). This is likely to introduce major uncertainties for any merchant investment in transmission or generation assets, and potential conflicts of interest in the way TSOs can influence the design and specifications of the SDAC and SIDC algorithms. Therefore, **Eurelectric requests that rules for such price indeterminacy situations are embedded in the algorithms** (e.g. by enforcing the additional rule that there should be a non-zero congestion rent for the TSO if and only if there is congestion) **and are defined together with TSO, NEMO, NRA and Market Parties, through an appropriate governance framework. Moreover, the impact on the performance of the Capacity Allocation algorithm in the case of OBZ has to be duly considered to avoid any step back.**

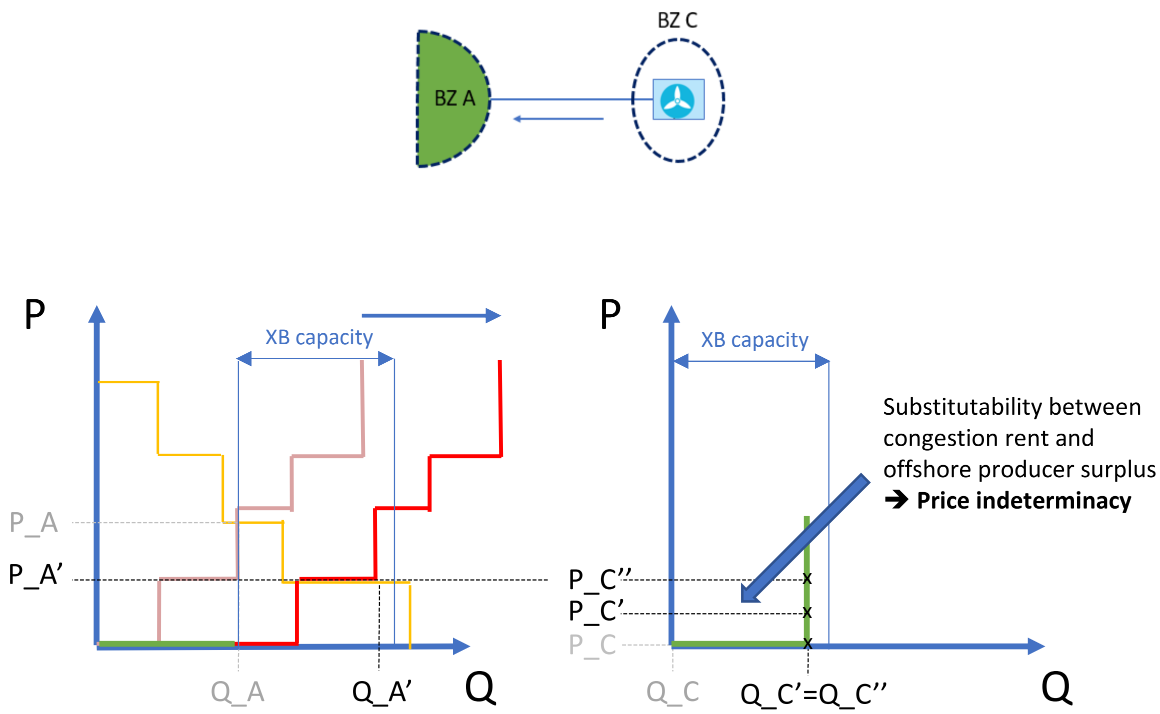


Figure 21 Illustration of the price determinacy issue

Current market legislation impacting hybrid projects

The following list gathers the legal and regulatory references that have an impact on the scope of this position paper. This notably shows the complexity of the issues as it touches upon all the different market segments.

Treaty on the Functioning of the European Union (TF EU), Art 102: non-discrimination between internal and CZ trades. Materialized through Art 16 E-Reg.

TF EU Art 102 prohibits any abuse by a dominant party within the internal market which may affect the trade between the Member States. Moreover, the TF EU includes principles of the free movement of goods and non-discrimination between internal and cross-zonal exchanges. These rules and principles apply to the electricity sector and are specifically set out in Article 16 of the electricity regulation[48] (E-Reg) to ensure non-discrimination between internal and cross-zonal exchanges. The practice of TSOs limiting cross border capacity in a structural way to manage congestions within their control areas is against these principles. Interconnectors combined with OG (offshore hybrid projects) are likely to be negatively affected by this practice. This legislation shall ensure the efficient utilization of these projects.

CACM Art 33: criteria for bidding zone reconfiguration
Any bidding zone reconfiguration should consider the criteria of respecting network security, overall market efficiency and stability and robustness of bidding zones.

Those criteria will also have to be applied if separate offshore bidding zones are introduced for offshore hybrid projects.

Clean Energy Package (CEP) – E-Reg Art 5: balance responsibility for RES producers who have to bear the risk for incorrect prediction of production. Derogation for small/demonstration projects or existing installations.

All market participants shall be responsible for the imbalances they cause in the system. Each balance responsible party shall be financially responsible for its imbalances and shall strive to be balanced or shall help the electricity system to be balanced. However, Members States can give derogations to demonstrative innovative technologies and renewable energy sources (<400 kW and <200kW as of 2026). This means that the offshore wind farms which are part of hybrid projects shall also be balance responsible parties irrespective of the OBZ model or Home market model.

CEP- E-Reg Art 6.6: Each imbalance price area shall be equal to a bidding zone, except in the case of a central dispatching model where an imbalance price area may constitute a part of a bidding zone.

CEP – E-Reg Art 12: end of priority dispatch for RES (with no retroactive effect & some derogations for existing installations or small/demonstration projects - art 12.6) means full market-based dispatch. Art 12.7 states that priority dispatch must not be used to reduce CZ capacity (cfr art 16 E-Reg).

Only renewable energy sources (<400 kW and <200 kW from 2026) and demonstration projects for innovative technologies can benefit the priority dispatch (i.e., in a self-dispatch

[48] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market, for electricity, OJ L 158, 14.6.2019, p. 54–124

model, the prerogative of never being curtailed by the TSO/DSO, or only as a last resort measure). Priority dispatch is still applicable to RES projects commissioned before 4 July 2019. However, the priority dispatch for such projects shall no longer apply after the facility is modified. This is the case when a new connection agreement is required or when the generation capacity of the facility is increased. Also, priority dispatch shall be not used as justification for curtailment of cross-zonal capacities beyond what is provided for in art. 16 and shall be based on transparent and non-discriminatory criteria.

This rule shows the offshore wind farms which as part of hybrid projects shall not be eligible for priority dispatch anymore.

<u>CEP – E-Reg Art 13</u>: market-based redispatch is the preference. When non-market-based redispatch (read: curtailment) is applied, RES should be impacted as a last resource and compensation should be based on the Day-Ahead (DA) price (of the BZ the installation is connected to)

The redispatching shall be based on market-based mechanisms. Non-market based redispatch shall be used only when no market-based alternative is available or when market-based measures increase the level of internal congestion. RES shall only be subject to non-market-based downward redispatching if no other alternative exists or if other solutions would result in significantly disproportionate costs or severe risks to network security. When non-market-based redispatching is used, it shall be subject to financial compensation by the system operator. This financial compensation should be based on the net revenues from the sale of electricity on the day-ahead market that the facility would have generated without the redispatching request.

<u>CEP – E-Reg Art 14:</u>
The bidding zone configuration shall be designed in such a way as to maximize the economic efficiency and cross-zonal trading opportunities while maintaining the security of supply. A bidding zone review shall be carried out to ensure an optimal configuration. BZs shall be assessed based on their ability to create a reliable market environment which is vital to avoid grid bottlenecks taking into account structural congestions, balancing electricity demand and supply and securing the long-term security of investments in network infrastructure.

<u>CEP – E-Reg Art 16.4: 70% rule</u>
TSOs shall ensure that the maximum level of capacity of interconnections and transmission networks affected by cross-zonal capacity is available for market participants while ensuring a secure network operation. RDCT, including the cross-border redispatch, shall be used to maximize this capacity available which shall be at least 70% of the transmission capacity. Cross-border remedial actions shall be carried out to maximize this available capacity in a coordinated and non-discriminatory way.

<u>CEP – E-Reg Art 16.8: 70% rule</u>
TSOs shall not limit the interconnection capacity available to market participants as a mean of solving congestion inside their own BZs or as a mean of managing flows resulting from transactions internal to BZs. For borders using a coordinated net transmission capacity (NTC) approach, the minimum capacity available shall be 70 % of the transmission capacity respecting operational security limits. For borders using a flow-based approach, the minimum capacity shall be a margin set in the capacity calculation process as available for flows induced by cross-zonal exchange. The margin shall be 70 % of the capacity respecting operational security limits of internal and cross-zonal network elements.

CEP – E-Reg Art 19: use of congestion rent

The distribution of congestion rent revenues shall neither distort the allocation process in favour of any party requesting capacity or energy nor provide a disincentive to reduce congestion. Allocation of congestion rent revenues shall prioritize:

- guaranteeing the actual availability of the allocated capacity including firmness compensation and
- maintaining or increasing cross-zonal capacities through optimisation of the usage of existing interconnectors using coordinated remedial actions or covering costs resulting from network investments that are relevant to reduce interconnector congestion.

If the above objectives have been adequately fulfilled, the revenues may be used as income which has to be taken into account by NRAs when approving the methodology for calculating or fixing network tariffs. The residual revenues shall be placed on a separate internal account line until such a time it can be spent for these objectives.

As proposed by EC in the Staff Working Document (SWD) accompanied by its offshore RES strategy, a redistribution of congestion rent income is considered/investigated to mitigate the revenue risks that would be faced by the offshore wind farm generators in an offshore bidding zone model. EC is considering to what extent to amend the rules to allow for a re-allocation of congestion revenues.

CEP – E-Reg Recital 38

There should be rules on the use of revenues from congestion-management procedures unless the specific nature of the interconnector concerned justifies an exemption from those rules.

CEP – Electricity Directive[49] (E-Dir), Art 3: the Member States shall not hamper cross-zonal trade

The Member States shall ensure that their national law does not unduly hamper cross-zonal trade in electricity including through demand response, investments into variable and flexible energy generation, energy storage, new interconnectors between the Member States etc. and hence ensure that electricity prices reflect actual demand and supply.

CEP – E-Dir Art 6: non-discriminatory grid access

The Member States shall ensure the implementation of a system of third-party access to the transmission and distribution systems based on published tariffs, applicable to all customers and applied objectively and without discrimination between system users. TSOs or DSOs may refuse access where it lacks the necessary capacity. However, duly substantiated reasons shall be given for such a refusal.

As per this rule, Member States should ensure that offshore hybrid projects have non-discriminatory access to the grid.

Governance Regulation[50], Art 4 on positive CBA for IC projects

Every new interconnector shall be subject to a socioeconomic and environmental cost-benefit analysis and implemented only if the potential benefits outweigh the costs.

[49] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity, OJ L 158, 14.6.2019, p. 125–199

[50] Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action, OJ L 328, 21.12.2018, p. 1–77

The interconnectors connecting offshore hybrid projects to various markets shall be subject to this cost-benefit analysis.

Glossary

Term or acronym	Meaning or definition
Art	Article
BAL	Balancing
BRP	Balance Responsible Party
BSP	Balancing Service Provider
BZ	Bidding Zone
BZR	Bidding Zone Review
CA	Capacity Allocation
CACM GL	Capacity Allocation and Congestion Management Guideline
CBA	Cost-Benefit Analysis
CBMP	Cross-Border Marginal Price
CC	Capacity Calculation
CEP	Clean Energy Package
CfD	Contract for Difference
CM	Congestion Management
CNE	Critical Network Element
CR	Congestion Rent
CT	Countertrading
CZ	Cross-Zonal
CZ ID	Cross-Zonal Intraday
DA	Day ahead
DA CC	Day ahead Capacity Calculation
DA MC	Day ahead Market Coupling
DSO	Distribution Service Operator
EB GL	Electricity Balancing Guideline
EC	European Commission
E-Dir	Electricity Directive
EEAG	Energy and Environmental State Aid Guidelines
E-Reg	Electricity Regulation
EU	European Union
eur	Euros
FCA GL	Forward Capacity Allocation Guideline
Fmax	maximum transmission capacity of a network element

FTR	Forward Transmission Right
GCT	Gate Closure Time
GL	Guideline
GW	Giga Watts
HM	Home Market
HM-COMP	Home Market setup compliant with the threshold set under the Art 16.8 of E-Reg (aka 70 % rule)
HM-EXEM	Home Market setup benefitting from an exemption to apply the 70 % rule (thru a formal derogation or thru an amendment of the relevant legislation)
HVDC	High Voltage Direct Current
IC	Interconnector
ID	Intraday
ID CC	Intraday Capacity Calculation
ID CC&A	Intraday Capacity Calculation & Allocation
ID GCT	Intraday Gate Closure Time
ID MC	Intraday Market Coupling
IGCC	International Grid Control Cooperation
ISO	Independent System Operator
JV	Joint Venture
kW	Kilowatt
LFC	Load-Frequency Control
LPF	Level Playing Field
LT	Long-Term
LT CC	Long-Term Capacity Calculation
LTTR	Long-Term Transmission Right
MACZT	Margin Available for Cross Zonal Trade
MARI	Manually Activated Reserves Initiative
MC	Market Coupling
MINE	Multipurpose Internal Network Element
MP	Market Participant
MS	Member State
MTU	Market Time Unit
MW	Megawatt
NEMO	Nominated Electricity Market Operator

NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OBZ	Offshore Bidding Zone
OG	Offshore Generation
ORES	Offshore Renewable Energy Strategy
OWF	Offshore Wind Farm
PCIs	Projects of Common Interest
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PTDF	Power Transfer Distribution Factor
RA	Remedial Action
RCC	The Regional Coordination Centres
RD	Redispatching
RDCT	Redispatching and Countertrading
RES	Renewable Energy Sources
RR	Replacement Reserve
RT	Real Time
SDAC	Single Day-Ahead Coupling
SEW	Socio-Economic Welfare
SIDC	Single Intraday Coupling
SO GL	The System Operation Guideline
SWD	Staff Working Document
TEN-E	Trans-European Network for Energy
TERRE	Trans European Replacement Reserves Exchange
TF EU	Treaty on the Functioning of the European Union
TSO	Transmission System Operators
TYNDP	Ten Year Network Development Plan
XB	Cross-Border
XB ID	Cross-Border Intraday

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- Growth, added-value, efficiency

Environmental Leadership

- Commitment, innovation, pro-activeness

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- Transparency, ethics, accountability

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