North Sea
Wind Power Hub
Programme

Regulatory & market design

Commercial framework offshore bidding zone

Risks and mitigation measures associated with offshore bidding zones for offshore wind farm and power-to-gas developers

Discussion paper

#4

Co-financed by the Connecting Europe Facility of the European Union

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Published by
North Sea Wind Power Hub, May 2023

North Sea Wind Power Hub feasibility and preparation studies (1.19-0001-NLDE-S-M-20) is co-financed by the Connecting Europe Facility of the European Union.

About this paper

Why read this report

Clarity on commercial framework, including risk and mitigation measures, for an offshore bidding zone (OBZ) market setup is crucial for investment decisions by offshore wind farm (OWF) and power-to-gas (PtG) developers. This discussion paper uses the OBZ market setup as a starting point and intends to inform policy makers and relevant stakeholders, including OWF and PtG developers, about potential consequences and opportunities. The paper identifies risks for investors in OWFs and PtG when changing the market setup from a home market (HM) approach to an OBZ market setup and makes an assessment and proposal of potential mitigation measures. How risks should be allocated to the involved stakeholders is a political decision that needs to be taken before tendering so that a transparent level playing field is provided to developers to calculate their business case.

Highlights

Changing the market setup offshore will result in a change of risks for (offshore) developers. In order to effectively roll-out offshore bidding zones, mitigation measures may be needed to address some of these risks.

The key difference with a HM setup is that in an OBZ, developers depend on the available capacity of interconnectors that connect to adjacent bidding zones. These interconnectors are not only used to transport offshore wind generated electricity to shore, but also for trading electricity between between bidding zones.

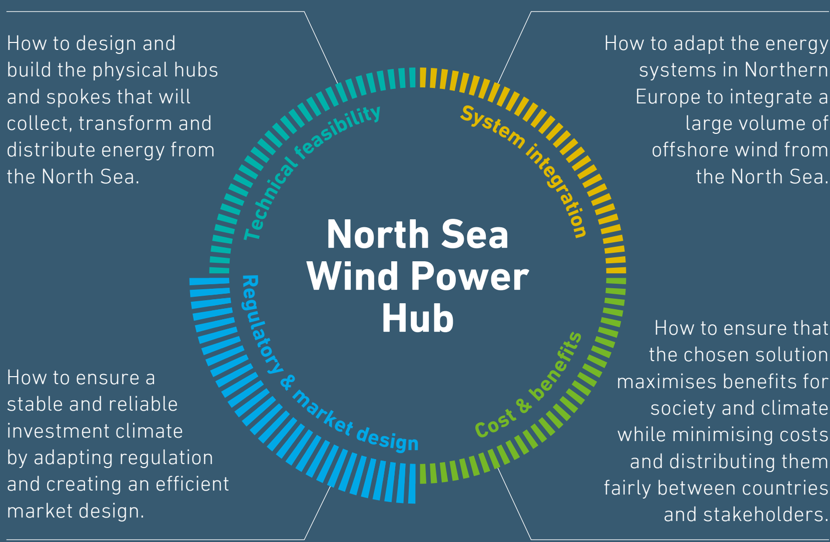
A balanced and stable development of offshore generation, hydrogen and electricity grids will provide a degree of certainty on installed offshore wind, power-to-gas and interconnection capacities, which is crucial to increase investment certainty on future developments related to the OBZ and their ability to better assess long-term market risks.

Several mitigation measures were examined, and certain low regret actions were identified that allow for a better assessment of the risks to developers in an OBZ market setup. Mitigation measures should be implemented by policy makers only for risks that developers cannot manage themselves. In addition, these risks do not necessarily need to be reduced to the same level as under the home market setup. However, the appropriate allocation of risks to stakeholders is ultimately a political decision.

The big picture

The North Sea is a powerhouse of wind energy. Harnessing this power requires us to cooperate across countries and borders to build an efficient network. To show that a solution can be achieved in a cost-effective and secure manner, the North Sea Wind Power Hub is working within four key areas.

This discussion paper explores key topics within system integration.



Glossary

Term	Abbreviation	Description
Advanced Hybrid Coupling	AHC	AHC fully takes into account the HVDC nature of a connection line, and influences of the adjacent capacity calculation regions during the capacity allocation.
Basis risk		Risk that the price of a specific electricity contract will differ from the price of a benchmark or reference contract.
Balance responsible party	BRP	A market participant that is responsible for ensuring that the electricity it consumes or produces is balanced with the electricity it receives or delivers to the grid.
Bidding zone	BZ	A bidding zone is the largest geographical area within which market participants are able to exchange energy without capacity allocation[1].
Capacity Allocation and Congestion Management Regulation	CACM regulation	The CACM regulation provides binding rules for the implementation and operation of EU-wide single market coupling in the day-ahead and intraday timeframes[2].
Contract for Difference	CfD	CfDs can be used as a support mechanism. A CfD is a contract that obliges the parties to pay the spread between a defined reference price and a strike price. The strike price can be fixed (like in classical support mechanisms) or variable.
Delegated Act	DA	Article 27 of the Renewable Energy Directive (Directive (EU) 2018/2001 (RED II), which can still be discarded at the time of writing of this paper, specifies a Union methodology on the production criteria of green hydrogen[3].
Electricity regulation		Regulation (EU) 2019/943 on the internal market for electricity provides a framework for the further integration of renewable energy into the electricity market, sets out new rules on bidding zones and cross-zonal capacity allocation and reenforces the role of the market in providing price signals for investment[4].
Exclusive Economic Zone	EEZ	The exclusive economic zone is an area in which sovereign states have jurisdiction over resources. The EEZ comprises an offshore area which extends from the coast (6 to 22 kilometre, in most cases) to 370 kilometres off the coast[5].
Financial Transmission Right	FTR	An FTR is a financial instrument that entitles the holder for renumeration equal to the price difference on a bidding zone border in a certain direction.
Firmness		A guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed[6].
Flat price risk		Flat price risk refers to the uncertainty about the future absolute price level.
Forward capacity allocation	FCA	FCA provides rules on cross-zonal capacity calculation and allocation in the forward timeframe[7].
Futures		Financial products of traded electricity, which are settled against spot market prices of future delivery periods and are standardised contracts on power exchanges[8].

1 ACER has decided on alternative electricity bidding zone configurations, 2022. Link
2 Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management. Link
3 COMMISSION DELEGATED REGULATION (EU) of 10.2.2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin. Link
4 Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast). Link
5 Retreived from OECD.Stat. Link
6 ACER has decided on alternative electricity bidding zone configurations, 2022. Link
7 Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation. Link
8 Retreived from TenneT official website: "What kind of markets are there and how do they work?". Link

Home market	HM	Market setup for offshore hybrid projects in which the offshore wind farm is inherently part of the onshore bidding zone. The home market is decided by the location of the wind farm, e.g., in which EEZ it is located in. (e.g. a Dutch wind farm would have the Dutch onshore bidding zone as a home market)
Infrastructure		Electrical infrastructure unless stated differently.
Interacting price/volume risk		Mutually dependent price and volume changes.
Interconnector	IC	A transmission line for electricity, unless specified otherwise, which spans the border between two EU countries and connects their national transmission systems.
Joint Allocation Office	JAO	The JAO platform is a marketplace on behalf of TSOs for the auctioning of long- and short-term auctions of transmission capacity rights.
Long position		An expectation of a market participant that the price of electricity will increase in the future.
Market maker		Supports exchange liquidity directly and is given formal obligations to post bids and offers for a specific product or set of products.
Offshore bidding zone	OBZ	An offshore bidding zone is the largest offshore geographical area within which market participants are able to exchange energy without capacity allocation[9].
Offshore wind farm	OWF	A power plant that contains all facilities needed to capture wind power, transform it into electricity and supply it to the main electricity network.
Regulated asset base	RAB	Regulated Asset Base (RAB) is an assessment of adequacy and efficiency of a company's proposed investment program for the forthcoming regulatory period.
Regulatory risk		Policy and regulatory decisions that may impact prices or volumes.
Short position		An expectation of a market participant that the price of electricity will decrease in the future.
Transmission Access Guarantee	TAG	A compensation mechanism to compensate OWF developers for a reduction of transmission capacity due to preventive congestion management by TSOs[10].
Transmission System Operator	TSO	An organisation committed to transporting energy in the form of natural gas or electrical power on a national or regional level, using fixed infrastructure. "TSO" and "infrastructure" refer in this paper to the electricity sector unless stated otherwise.
Ten-year network development plan	TYNDP	The 10-year network development plan (TYNDP) that ENTSO-E publishes every two years presents a plan on how to develop the power grid in the next 10 to 20 years so that it can effectively contribute to achieving security of supply, affordable energy prices and sustainable development[11].
Volume risk		Risk that the volume of electricity that is traded differs from the expected volume, independent of price changes.
Power Purchasing Agreement	PPA	Bilateral energy contracts whereby a buyer agrees to purchasing electricity from a generation asset at a fixed price for an extended period of time.
Power-to-Gas	PtG	Power-to-Gas means converting power into gaseous hydrogen.
Priority access		Prioritising access to an interconnector implies preferential access of one market party to an interconnector to ensure that capacity is available when needed.

[9] Article 2(65) REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on the internal market for electricity (recast).
[10] Support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market, ENGIE Impact, 2022. Link
[11] Retreived from ENTSO-E's official website. Link

Executive summary

The large-scale deployment of offshore wind in the North Sea that includes solutions like the hub-and-spoke concept and power-to-gas (PtG), requires a suitable offshore market setup to ensure efficient market and system operation | The North Seas Energy Cooperation (NSEC) agreed in a statement to jointly reach 260 GW of installed capacity of offshore wind in the North Sea by 2050[12]. To integrate such large quantities of offshore wind in the European grid in an efficient manner, NSEC countries[13] explore the development of hybrid and joint projects[14]. Implementing hybrid and joint projects requires cooperation and strengthening of EU electricity market arrangements, and in particular, clarity on the offshore market setup.

An offshore bidding zone (OBZ) market setup improves market and system operation efficiency, reflects physical limitations of the grid and provides appropriate price signals to market parties. Changing any market setup will introduce risks to market parties that should be identified and possibly mitigated | Two offshore market setups are considered and explored at the European level: the home market setup and the offshore bidding zone market setup. An offshore bidding zone forms a separate price zone from the home market, and connections between offshore hubs and the shore classify as interconnectors.

Offshore wind farms (OWF) and on- and offshore power-to-gas (PtG) developers require clarity on the selected offshore market setup and a full understanding of the associated risks to make informed investment decision | Policy makers need to clarify the applicable offshore market setup and the required risk mitigation measures prior to investment decisions and (possibly joint) tenders for OWF and PtG. This paper aims to provide an understanding on the commercial framework for investors in an offshore hybrid project by assessing the risks, which are affected by an OBZ market setup. An overview of key risks and potential mitigation measures is presented. The analysis in this paper is refined by conducting interviews with a sample of developers and investors active in the North-West European electricity market. The interviews were conducted on an anonymous basis.

The key incremental risks for OWFs in an OBZ market setup versus a HM setup are mainly driven by the relatively small size of the bidding zone, referring to the limited demand and generation within the zone. This means that any incremental changes to the assets (e.g., size of load, generation and infrastructure) would have a greater impact on the price level in a smaller bidding zone, like the OBZ, compared to the larger HM bidding zone. Moreover, the dependency on the available capacity on the interconnectors under an OBZ is a risk that OWFs developers cannot manage themselves. Potential congestion on an interconnector, or technical unavailability or a delay in commissioning of interconnectors would lead to an increased price and volume risk, as well as an interacting price/volume risk (the unavailability of one interconnector can lead to greater volumes towards other OBZs, depressing prices there given a certain interconnector capacity and OBZ demand). Whether these risks are detrimental to the business case of the investors is an aspect that needs to be further assessed.

Offshore PtG faces mainly the mirrored version of the aforementioned risks, i.e., they can absorb volumes and benefit from changes in prices in the opposite direction (i.e., low price hours). Nevertheless, clarity on these risks is required for to be able to assess its business case. **Onshore PtG relies on the available interconnector capacity and its interests are more aligned with the OWFs, i.e., getting power to shore.** The main incremental risk relates to the conditions for onshore PtG to produce green electricity (in line with the EU Delegated Act on electricity use for production for green hydrogen).

[12] North Sea Energy Cooperation – Joint Statement on the North Seas Energy Cooperation, Sept 2022. Link
[13] Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and Sweden.
[14] Hybrid projects combine offshore generation and transmission assets, which conventionally operate as separate entities. This enables them to link projects and provides a platform for coordination between countries. Joint projects are two or more EU countries which can co-fund a renewable energy project in electricity, and share the resulting renewable energy for the purpose of meeting their targets. Link

Text box 1: Delegated Act

The Delegated Act was adopted by the European Commission on 10 February 2023 and is currently subject to a 2-month scrutiny period by the European Council and Parliament. The Parliament decided on 23 February 2023 to extend this scrutiny period by 2 months. The outcome of the trialogue between European Commission, Parliament and Council is not yet clear at the time of writing of this paper, and could potentially lead to the rejection of the DA. This process has potential implications for the statements made in this paper.

An optimal risk allocation sees risks being borne by those actors that can efficiently manage them. How risks under an OBZ setup should be allocated is a political decision. In any case, **aligning measures to mitigate risks with policy objectives** is crucial to avoid unnecessary societal costs. This implies using the right measure to mitigate the directly corresponding risk.

Low-regret measures that help developers understand and better assess the risks they may face in a hybrid project under an OBZ market setup have been identified. This aligns with the views of stakeholders that were interviewed: first and foremost there is the need to be able to assess the risks.

- **Administrative compensation schemes set up between OWFs and TSOs**, similar to existing offshore radial connections, would provide contractual clarity about potential compensation for the technical unavailability or a delay in the commissioning of the interconnector between the OBZ and onshore BZ. Particular consideration, however, needs to be given to the definition of the compensation scheme, including the definition of the correct benchmark for technical availability, the specific risk to TSOs associated with delays in commissioning of HVDC-assets, as well as the spill-over effects to other jurisdictions.
- **Increasing transparency on the available interconnector capacity and improving market participant's understanding of capacity allocation,** particularly under the flow-based and advanced hybrid market coupling is crucial. Such transparency could be provided by further studies on the network representation in general, simulations that resemble a planned hub (ex-ante), timely and user-friendly disclosure of allocated interconnector capacities and further disclosure and interaction with market participants when results are unexpected (ex-post).
- **Offshore development plans,** such as planned interconnectors and additional build-out of OWF and PtG capacity, provide indications to investors on future developments that affect the OBZ and allow them to better assess long-term risks. Implementing binding commitments is administratively feasible, but there will be political and legal challenges in achieving this (e.g. getting political commitment to a long term integrated (electricity and hydrogen) infrastructure plan, subject to uncertainty and inflexibility).

Dealing as directly as possible with risks of interconnector unavailability is considered very desirable by interviewed stakeholders | OWFs in an OBZ depend on the availability of interconnector capacity to export electricity to shore. This brings a risk that developers are unlikely to be able to manage themselves. As mentioned above, administrative compensation schemes are desirable by stakeholders to reduce risks stemming from technical unavailability or delays in commissioning of interconnectors. Other mitigation measures such as financial transmission rights (FTRs), Contracts-for-difference (CfDs), etc. could reduce volume risks associated with the impact of flow-based or advanced hybrid market coupling. However, interviewed stakeholders did not express clear preference for a certain instrument.

The aforementioned mitigation measures have desirable elements, but an integral approach or commitment that deals with all sources of unavailability and across borders might be required. To this end, support schemes that remunerate the OWFs for their availability rather than actual production could be an option to protect investors from both price and volume risks. This would make revenue streams more predictable and thus, de-risk investments in hybrid offshore projects. The need for public support should be revealed and determined in a transparent way, i.e., through auctions for offshore wind. It is noted, that implementing a measure that does not directly interfere with existing electricity and proposed hydrogen market regulation is preferrable.

Providing stability for the development in the first years of the roll-out is crucial | In order to maintain the interests of investors for a balanced and stable development of the OBZ, it is important to provide a degree of certainty on installed capacities (electricity generation, IC, PtG) in the OBZ for the first years of the roll-out, while recognizing the flexibility required by TSOs and governments to adjust over time. This ensures that investors benefit from protection in the year's most valuable to the business case, while still allowing for a rapid roll-out of offshore wind. To this end, joint tendering of OWFs and PtG could be an option to reduce the risk of coordination failure, leading to the reduction in price and volume risks faced by the OWF and PtG units. However, this measure would increase the risk of a central planner imposing outcomes that might be different from market outcomes. The stakeholders that were interviewed requested that indeed some parameters (electricity generation, IC, PtG) would need to be fixed given the small size of the OBZ, but at the same time stressed that within certain parameters, markets would be able to deliver efficient outcomes with limited need for further coordination.

Text box 2: Recommendations to policy makers

- Should an OBZ market setup be implemented for hybrid offshore projects, the North Sea Wind Power Hub (NSWPH) consortium would recommend policy makers to **apply the identified low-regret measures** (if not in place already) in order to allow stakeholders to better understand the risks they potentially face, hereby increasing investment security. If there are remaining risks that are detrimental to the business case of OWFs, these should be revealed in a transparent way.
- **Mitigation measures should be designed in a way that aligns with the policy objectives** and follow the **guiding principles for the EU internal market** to ensure unnecessary societal costs are avoided and the measures are non-discriminatory.
- Due to the multinational playing-field of hybrid offshore projects, there are certain aspects that require particular attention from policy makers. These include the impact of the **long-term roll-out strategy** and the certainty around this, and the impact of possible mitigation measures in one OBZ affecting neighbouring OBZs (**spill-over effects**). The design of an OBZ is subjected to its national policies.

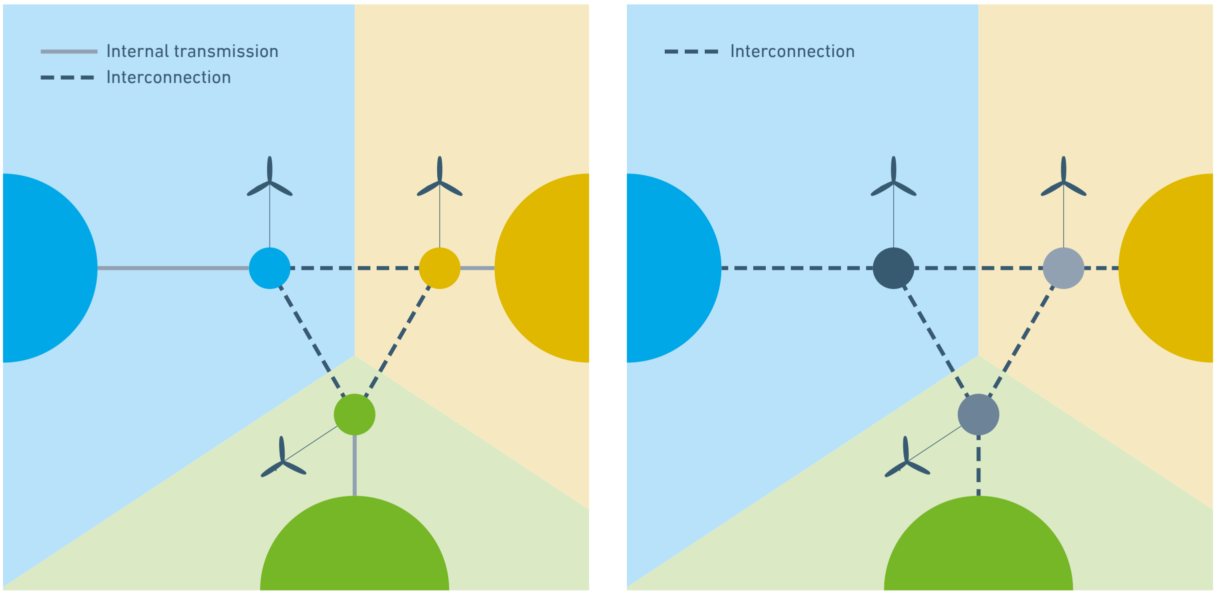
1 Offshore bidding zones: a promising solution

In September 2022, nine North Seas Energy Cooperation (NSEC) countries agreed in a Joint Statement to reach at least 260 GW of installed capacity of offshore wind in the North Sea by 2050[15]. Intermediary targets agreed upon were 76 and 193 GW in the years 2030 and 2040, respectively. The NSEC aims to connect the nine member countries[16] by means of an offshore grid, to promote renewable energy and boost economic growth.

To integrate such large quantities of renewable energy in the European grid in an efficient manner, NSEC countries monitor and facilitate the development of specific projects and develop concepts for hybrid and joint projects[17] in the North Sea. A hybrid and joint project can include solutions like the hub-and-spoke concept and power-to-gas (PtG). In addition, hybrid and joint projects require a framework that considers how to remove legal, regulatory and market related barriers. Developing such a framework requires international cooperation and strengthening of EU electricity and hydrogen market arrangements.

In previous discussion papers, the North Sea Wind Power Hub consortium (NSWPH) extensively discussed two relevant offshore market setups: the Home Market (HM) setup and the Offshore Bidding Zone (OBZ) market setup, see Figure 1. The NSWPH consortium investigated how an OBZ can be established[18] and discussed the implications for OWF stakeholders[19].

Figure 1: Home market setup (left) versus offshore bidding zone market setup (right) between three countries.



[15] Nort Sea Energy Cooperation – Joint Statement on the North Seas Energy Cooperation, Sept 2022. Link
[16] Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and Sweden.
[17] Hybrid projects combine offshore generation and transmission assets, which conventionally operate as separate entities. This enables them to link projects and provides a platform for coordination between countries. Joint projects are two or more EU countries which can co-fund a renewable energy project in electricity, and share the resulting renewable energy for the purpose of meeting their targets.
[18] NSWPH – A strategy to establish an offshore bidding zone for hybrid projects, May 2022. Link
[19] NSWPH – Offshore Wind Market Engagement, May 2021. Link

OBZs are identified by the European Commission[20], ACER and CEER[21], and ENTSO-E[22] as a promising solution, which can act as a tool to efficiently integrate offshore wind. In the HM setup, the offshore wind farm bids and dispatches into its home market and receives the HM electricity price. The cable from the offshore hub to shore is a hybrid asset within the home market, and is classified as an internal transmission cable, whereas the cables between hubs in their respective home markets are cross-border interconnectors. In the OBZ, in contrast to a HM setup, generation from the OWF is substantially higher than the demand. Electricity generation in an OBZ is purely based on renewable energy, which is predominantly exported to adjacent BZs. The wholesale electricity price in an OBZ is the result of market coupling and, in the absence of any local demand, converges to the price of the onshore market to which the OWF's power can be delivered without congestion.

Highlight
It is the Commission's view that establishing offshore bidding zones provides a good approach to ensure compliance with the cross-border trading rules.

In addition, in the OBZ market setup, the cables from the hub to adjacent BZs are considered as cross-zonal interconnectors rather than transmission lines within a bidding zone. Regulation 2019/943 on the internal market for electricity[23] lays out the principles of capacity allocation and congestion management. Pursuant to Art 16(8a): Transmission System Operators (TSOs) shall maximise interconnector capacity and allocate a minimum of 70 percent of the cross-border capacity for cross-zonal trading while respecting operational security limits. This 70 percent rule has impact on the interaction between cross-border electricity trade and the export of offshore wind in a HM market setup. Additionally, as 100 percent capacity allocation cannot be guaranteed in market coupling, the 70 percent-rule may impact the expected allowed offshore production that can be exported to adjacent bidding zones.

An OBZ market setup is considered to improve market and system operation efficiency, allows market representation of the physical limitations of the grid, and provides appropriate price signals to market parties including PtG developers. However, the implementation of an OBZ market setup comes with market and regulatory risks through the introduction of a new bidding zone[24]. Nevertheless, an OBZ in itself should not be a regulatory risk as long as the market setup is clear before the tendering of the wind areas.

1.1 Setting the factual and counterfactual for offshore wind farms and power-to-gas installations

Two main types of generating or consuming assets can be included in hub-and-spoke projects, namely offshore wind farms (OWFs) and power-to-gas (PtG) installations. The timeline to define the setup may differ between OWF developers and PtG developers. OWF developers require clarity of the offshore market setup before site tenders take place and PtG developers need clarity before making an investment decision. Alignment on the timelines is important when planning electrical and hydrogen infrastructure/assets, where appropriate.

[20] The view of the EC on the different market setups is found in the working staff document, EU strategy on Offshore renewable energy. Here it is stated that *"it is the Commission's view that establishing offshore bidding zones provides a good approach to ensure compliance with the cross-border trading rules"* and that *"offshore bidding zones achieve a higher degree of overall efficiency than the 'home zone' approach"*. Link

[21] ACER and CEER REFLECTION ON THE EU STRATEGY TO HARNESS THE POTENTIAL OF OFFSHORE RENEWABLE ENERGY FOR A CLIMATE NEUTRAL FUTURE, April 2022. Link

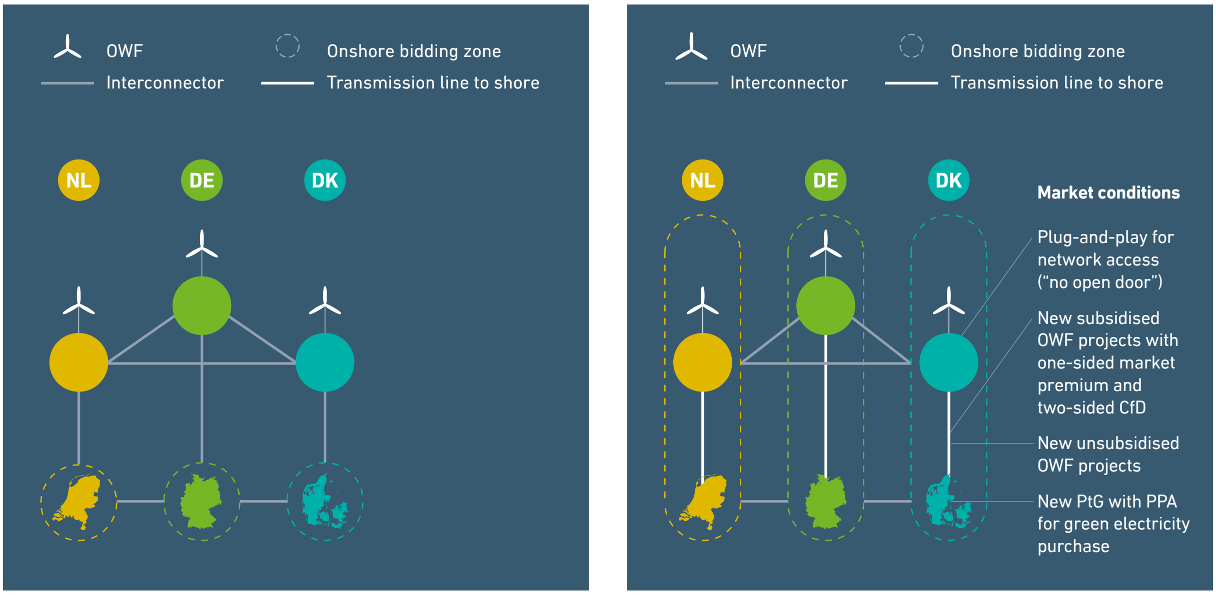
[22] ENTSO-E's views on offshore development. Link

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

[24] Which is no different from the possibility of splitting an onshore BZ.

The analysis in this study uses a conceptual framework to compare and assess the impact from an offshore bidding zone on risks for the selected market participants. The comparison analysis uses two scenario's: the factual scenario for OWF and PtG in which the generation facilities are located in an OBZ and a so-called counterfactual scenario with a HM setup, see Figure 2 and Figure 3.

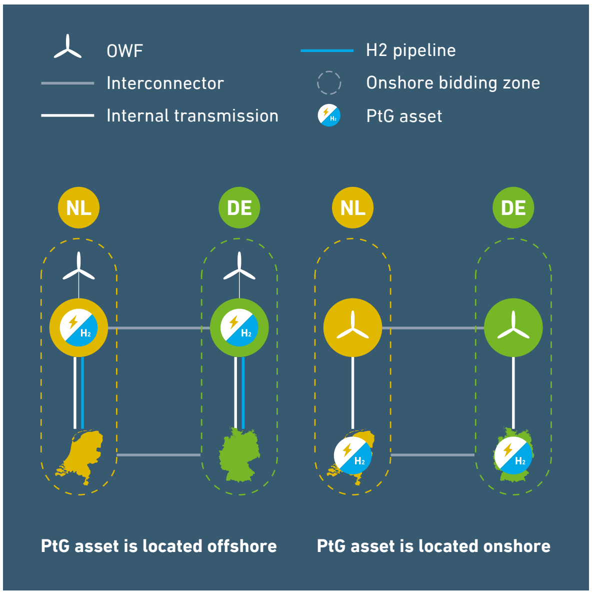
Figure 2: The factual (left) and counterfactual (right) market setup for an offshore wind farm (OWF).



Under the factual scenario, the OWFs are located in an OBZ. It is expected that for each platform or hub a separate OBZ would be implemented. This has the following implication for the classification of transmission lines: the transmission lines connecting the onshore and offshore BZs are classified as interconnectors. Additionally, there are several implications for both off- and onshore BZs in each country, including that prices may differ in off- and onshore BZs when transmission constraints occur on the interconnectors.

Under the counterfactual scenario, a HM setup is adopted meaning that the OWFs are located in their national country (e.g. Dutch wind farms are part of the Dutch onshore bidding zone). This has implications for the classification of transmission lines: only the transmission lines connecting the offshore wind farms to foreign countries are classified as interconnectors. The connection from the OWF to shore is part of the internal transmission network within the respective BZ. In addition, the OWF receives the electricity price of its national bidding zone. This means that a single price is applicable within the HM bidding zone.

Figure 3: The factual (left) and counterfactual (right) market setup for Power-to-Gas (PtG) assets.



Under the factual scenario, PtG assets can have two different locations, namely onshore and offshore. Irrespective of the location of the PtG, the factual scenario assumes an OBZ in which the OWF is located. When the PtG facility is located onshore, it is not inherently part of the OBZ but rather of the onshore bidding zone. Only when the facility is located offshore this study assumes the PtG assets to be part of the OBZ next to the OWF. In this setup, PtG assets can produce green hydrogen, and depending on their location, more options are available for electricity procurement. Specifically, assets located offshore are now located in an OBZ with 100 percent renewable electricity generation from offshore wind farms. As a result, the PtG asset can still enter into a power purchase agreement (PPA)with an offshore wind farm for the hydrogen to be qualified as green, but it can also procure green electricity directly from the OBZ grid when it is ensured that the requirements of article 4, which depicts the conditional requirements for electricity from the grid counted as fully renewable, of the EU Delegated Act are followed[25]. Onshore PtG, in contrast, still relies on a PPA with offshore wind farms for the hydrogen to be qualified as green. However, spatial correlation is achieved by entering into a PPA with an OWF located in the OBZ. The available interconnector capacity between the OBZ and the onshore BZ is here a limiting factor.

Highlight

In an OBZ with 100 percent renewable electricity, offshore PtG assets can produce green hydrogen based on electricity from the OBZ grid or based on a PPA.

Under the counterfactual scenario for PtG assets, a HM setup is adopted meaning that all assets within the EEZ of a member state are inherently part of a single bidding zone (the national bidding zone of the member state). Similar to the factual scenario, PtG assets can be located offshore or onshore. Producing hydrogen that is qualified as green, requires PtG assets to enter into a PPA with OWFs as electricity from the grid may not meet the Delegated Act criterion

[25] In a theoretical situation, the OWF including PtG is build and commissioned in 2030 under an OBZ. Pursuant to article 4(1) of the DA, focus is on the previous calendar year as benchmark year. However, this is not a suitable benchmark year as the OBZ didn't exist. Therefore, still a PPA might be required despite the fact that all the electricity in that (O)BZ is green.

from 2028 onwards[26]. For offshore PtG, the asset is located on the offshore hub, however, it is part of the single (national) bidding zone. As a consequence, it can secure its electricity directly through a PPA with OWFs, among other sources. In a hypothetical plug-and-play scenario, hydrogen pipelines are sufficiently large to transport hydrogen from the offshore hub to the shore. For onshore PtG, the asset needs to enter into a PPA contract with OWFs and would receive electricity via offshore cables. However, the amount of electricity that OWFs can deliver to shore is subject to potential transmission constraints.

1.2 Goal and approach of the paper

Text box 3: Goal

This discussion paper is meant to provide understanding of the commercial framework, including the key risks, for investors in OWFs and PtG installations when changing the market setup from a HM to an OBZ and to present possible mitigation measures that could address these risks.

This paper outlines the different risks for OWF and PtG developers associated with an OBZ market setup. Risks associated with an OBZ market setup mostly relate to market and regulatory risks. Further, the paper outlines possible mitigation measures that can address these risks associated with OWF and PtG development in an OBZ and thereby increase investment security. Low-regret actions are identified which allow stakeholders to better understand the risks they potentially face in an OBZ.

The described results and recommendations have been achieved through a combination of stakeholder engagement interviews and an extended literature review. The primary source for this work builds upon previous work by NSWPH as well as recent industry publications on the risks and mitigation measures within an OBZ market setup. Stakeholder interviews were conducted with OWF and PtG developers and developers active in the North-West European electricity market. These interviews were conducted on an anonymous basis.

This paper first presents the key risks for OWF and PtG developers in an OBZ in section 2, whereafter mitigation measures are provided in section 3. Section 4 presents the conclusions of key risks and mitigation measures and recommendations to policy makers.

[26] COMMISSION DELEGATED REGULATION (EU) of 10.2.2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin. Link

2 Key risks for developers in an offshore bidding zone

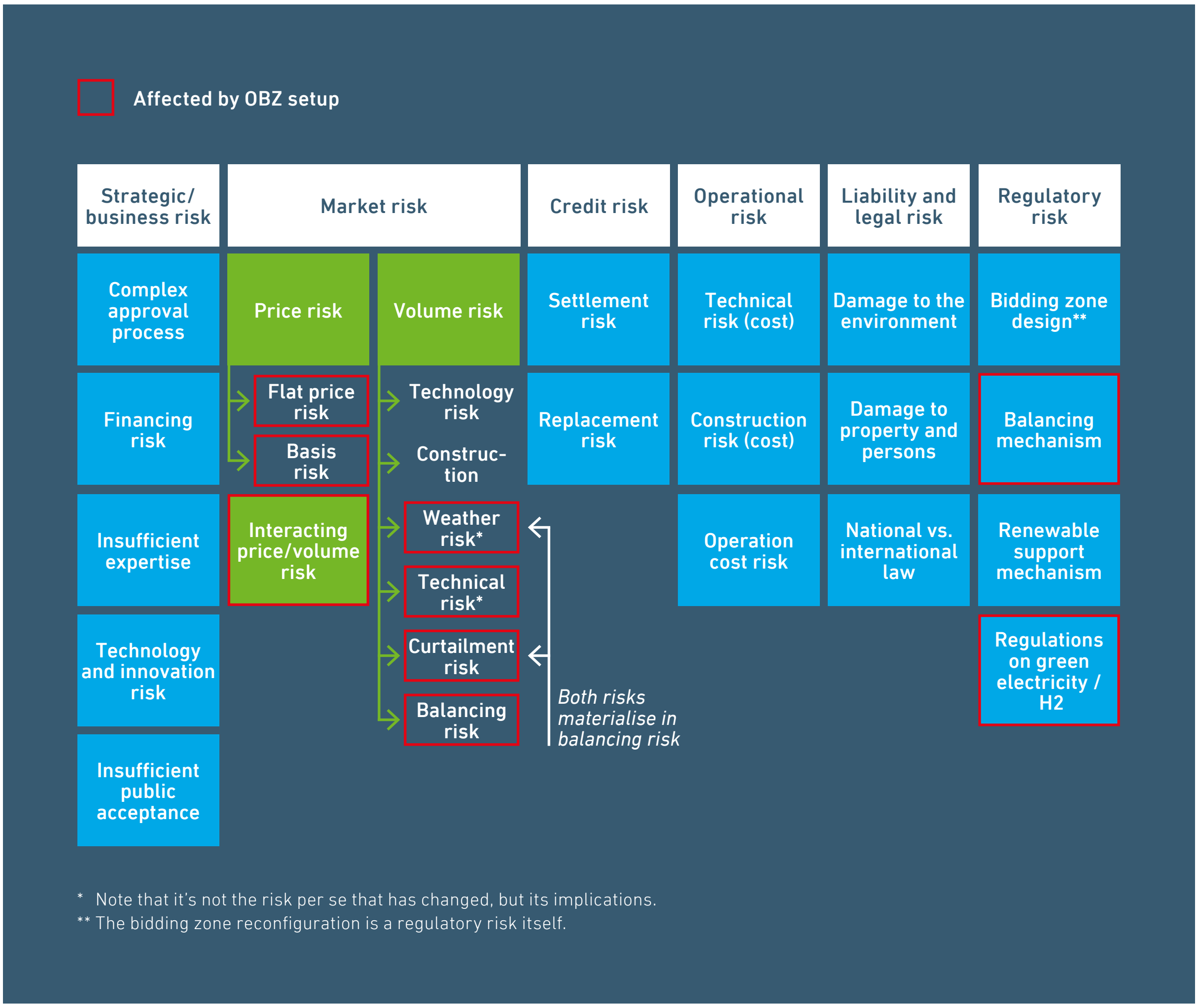
Text box 4: Key messages

- It is imperative to have a full overview of risks for developers in an offshore bidding zone market setup to ensure appropriate mitigation measures are developed and timely implemented if needed, and to ensure investment confidence for developers.
- The risks for OWFs immediately affected by the OBZ market setup are mainly market risks complemented by regulatory risks, namely (1) basis location risk, (2) flat price risk (what will be the capture price in the OBZ), (3) volume risk (how much electricity can be traded in the market), (4) interacting price/volume risk (greater volumes depress prices given certain interconnection capacity and OBZ demand), and (5) regulatory risk (policy and regulatory changes may impact prices or volumes).
- Irrespective of the offshore electricity market setup, PtG producers face risks concerning the uncertainties about the regulatory framework and the market setup for and classification of green hydrogen. At the time of writing, the Commission proposal for the Delegated Act will be submitted to the European Parliament and the Council for a two-month scrutiny period which can be extended to four months. The proposal can be accepted or rejected; it cannot be amended.
- PtG assets (onshore/offshore) face risks related to the classification of the produced hydrogen as green. This relates to the electricity they procure. Onshore PtG relies on the available interconnector capacity and its interest are more aligned with the OWFs, i.e., getting electricity to shore. The main incremental risk relates to the conditions for green hydrogen production (in line with EU Delegated Act on electricity procurement for production for green hydrogen). Offshore PtG (1) and a direct connection of an interconnector from the OBZ to the onshore PtG (2) can provide a hedge as they (1) do not face restrictions with respect to the export cable, and (1 and 2) do not face regulatory uncertainty with respect to procurement of green electricity.

2.1 Risk categories

Risks for OWF and PtG developers when changing from a HM to an OBZ market setup can be classified within six categories (see Figure 4). The sections below detail the main risk categories to developers affected by a transition to an offshore bidding zone configuration. The Appendix includes a description of other risk categories that are not directly affected by a transition to an offshore bidding zone market setup.

Figure 4: Overview of all risks that OWF and PtG developers can face. The red-marked squares imply risks affected by a transition to an offshore bidding zone market setup.



2.1.1 Market risks

Market risks, also known as systematic risks, refers to the risks inherent to the overall market or market segment in which an investment is made and include price risks (basis risks/ flat price risks), volume risks and interacting volume/ price risks. These risks are often correlated.

Price risks (basis risk/flat price risk)

Basis risk in electricity markets refers to the risk that the price of a specific electricity contract will differ from the price of a benchmark or reference contract. This can occur due to differences in delivery location, delivery period, or other specific terms of the contract.

Flat price risk refers to the risk that the absolute price level (the flat price) of electricity will fluctuate. This risk can be caused by a variety of factors, including changes in demand, supply disruptions, and changes in the cost of generating and delivering electricity. For example, a generator is uncertain about the future electricity price and whether this price is sufficient to make the investment profitable. The electrical export capacity for an OWF developer in an OBZ is defined by the available interconnection capacity from the offshore hub to adjacent bidding zones, whilst for offshore PtG, the hydrogen export capacity is defined by the flowrate and size of the pipelines to shore. Generally, at moments of congestion, prices can be lower offshore relative to onshore, resulting in a potentially lower market revenue for commercial merchant generation. In electricity markets, the term *"spread"* refers to the difference in price between two different contracts or benchmarks. The spread can be positive or negative and can be used to measure the relative value of different contracts or to identify opportunities for profit[27].

Highlight
Market risks concerns price spreads (locational or contractual), price volatility, the ability of the OWF to export its electricity to shore and the correlation between generation and the price.

Volume risk

Volume risk in electricity markets refers to the risk that the volume of electricity that is traded differs from the expected volume, independent of price changes. This situation can occur due to, for example, constraints of electricity transmission capacity (e.g., curtailment due to congestion management[28]) from an OBZ to an adjacent BZ, which can lead to an adverse impact for OWF and PtG developers. For offshore PtG developers, however, no constraints are foreseen for the transmission of hydrogen from sea to shore, on the condition that the capacity of hydrogen transmission infrastructure is designed accordingly.

Other risks impacting traded electricity volumes include *weather, technical* and *balancing* risks[29]. Weather risks relate to an inaccuracy in weather predictions, leading to a deviation between expected and actual electricity production by an OWF. Technical risks exist, for example, due to outages or maintenance (technical unavailability) of electrical and gas infrastructure. A mismatch between traded and expected volumes relates to balancing risks to the OWF developer as a balance responsible party (BRP).

Interacting price/volume risk

The interacting price/volume risk can be defined as mutually dependent price and volume changes. Interactions may turn *"simple"* volume risk into non-linear price risk. For example, in contrast to the simple volume risk, an OWF may be forced to sell surplus energy at times when other OWFs do so as well (so at declining prices) resulting from the surplus made available in the market. The interacting price/volume risk is not relevant for OWFs under a subsidy regime. However, similar risk as for unsubsidised OWFs are present in case of a one-sided market premium and zero-bids, or bids below the levelised cost of electricity (LCOE) of the OWF.

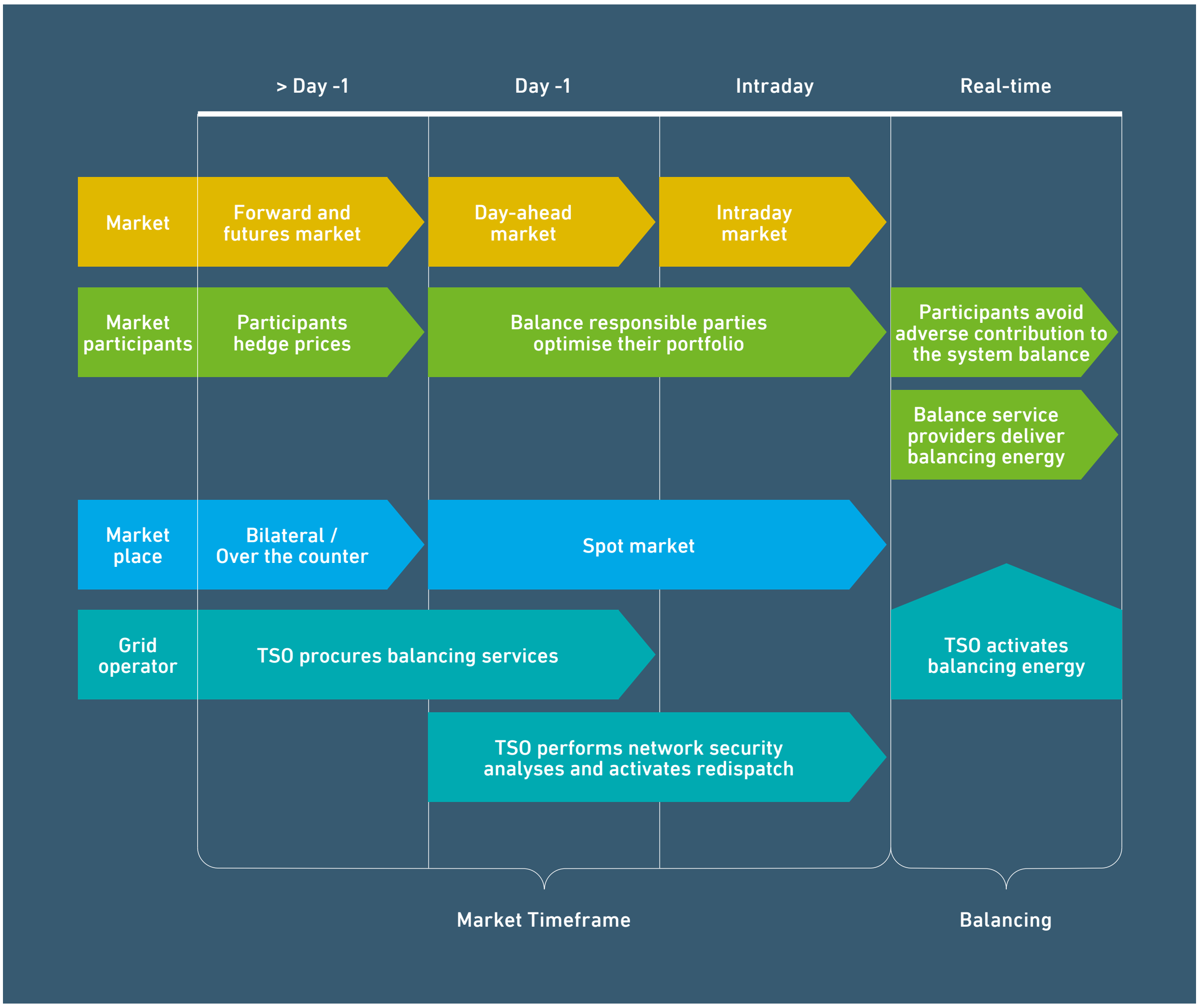
[27] There are several types of spreads that can be used in electricity markets. 1) Calendar spreads: These refer to the difference in price between contracts for different delivery periods. 2) Basis spreads: These refer to the difference in price between contracts for delivery to different locations. 3) Cross-commodity spreads: These refer to the difference in price between contracts for different energy sources, such as electricity and hydrogen.

[28] The set of processes and procedures used to ensure the secure and efficient operation of the power system, particularly when there is a mismatch between the electricity supply and demand.

[29] Volume deviation between the latest forecast and the realised generation. Short or long position is then sold to or bought from the grid operator at balancing prices, respectively.

Electricity is traded on a variety of markets in Europe at different volumes, prices, and timescales (outlined in Figure 5). Each market brings its own market risk and is therefore elaborated on in section 2.2. For hydrogen it is at the time of writing unclear what the exact market setup will look like, which is a direct market risk. Price and volume risks exist in both long- and short-term electricity markets, and risks differ depending on the timescales of the markets.

Figure 5: Overview of different electricity markets and role of market actors. The respective markets are elaborated in-text[30].



2.1.2 Regulatory risks

Regulatory risks are caused by policy and regulatory decisions that may impact prices or volumes, such as a change in market design or balancing market setup, the amendment of renewable support mechanisms or wider climate regulations. All these risks have a wide impact on market outcomes. Changing the market setup is a regulatory risk in itself since this introduces uncertainty for all market parties until a new market setup is identified and implemented.

[30] Retrieved from TenneT's official website: What kind of markets are there and how do they work. Link

In addition, misallocation of subsidies to different assets is a regulatory risk and appropriate support mechanisms should be in place for the appropriate assets[31]. In relation to these support mechanisms, a regulatory framework is at the time of writing in development for the procurement of green[32] electricity and, irrespective of the market set up, the production of green hydrogen. An input-related risk to produce green hydrogen[33] relates to the criteria that must be met for the procurement of electricity, in order for the produced hydrogen to qualify as green hydrogen (see break-out box on the Delegated Act[34]).

Text box 5: The Delegated Act (DA) on sustainability criteria

The Delegated Act (DA) on sustainability criteria establishes a Union methodology setting out detailed criteria to produce renewable hydrogen. The DA is required under article 27(3) of the Renewable Energy Directive (RED II). The RED II includes binding targets for the use of hydrogen and derivates in industry and transport.

In February 2023, the Commission has adopted a Delegated Act which proposes to include accounting indicators to produce renewable hydrogen. At the time of writing, the scrutiny period for accepting or rejecting the DA is ongoing and will be extended until June 2023.

From 1 January 2030, an hourly correlation between renewable electricity production and renewable hydrogen production is proposed. Until 31 December 2029, a monthly correlation is proposed. In extent, if the electricity clearing price resulting from single day-ahead market coupling is below or equal to 20 EUR/MWh, or lower than 0.36 times the allowance to emit one tonne of carbon dioxide during the relevant period. Furthermore for installations producing renewable hydrogen that came into operation before 1 January 2028, the requirements of articles 5 (a) and (b) will not apply until 1 January 2038. This means that the installation producing renewable electricity should have come into operation not earlier than 36 months before the PtG installation and that the renewable electricity installation has not received support. From 1 January 2028 onwards these requirements do apply. However, *individual Member States can still choose to enforce the additionality requirements,* leaving uncertainty for investors.

Electricity can be sourced from the grid of a single bidding zone when the average carbon intensity is lower than or equal to 65g CO_2-e/kWh, or the average share of RES is higher than or equal to 90 percent over a calendar year (or calendar year 2021). Once the latter conditions are met, electricity from the grid is counted so for the consecutive 5 years. Renewable energy generation units under a PPA should be located in an offshore bidding zone interconnected to the bidding zone where the PtG asset is located.

Renewable energy generation units must not have received support in the form of operating aid or investment aid. However, support received by renewables before repowering, financial support for land or grid connections and support that does not constitute net support are excluded.

[31] Only in case subsidies are needed to mitigate certain regulatory risks.
[32] Electricity produced from resources such as solar, wind, geothermal, biomass, and low-impact hydro facilities (EEA). Link
[33] COMMISSION DELEGATED REGULATION (EU) of 10.2.2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin. Link
[34] Delegated acts are on art. 27 and 28 of the RED II Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL amending Directive (EU) 2018/2001 of the European Parliament and of the Council, Regulation (EU) 2018/1999 of the European Parliament and of the Council and Directive 98/70/EC of the European Parliament and of the Council as regards the promotion of energy from renewable sources and repealing Council Directive (EU) 2015/652.

2.2 Key risks for offshore wind farm developers in an offshore bidding zone

Text box 6: Key messages

- The risks for OWF developers immediately affected by a transition to an OBZ market setup are mainly market risks.
- A generator faces new basis locational risk (between OBZ and neighbouring BZ) and hedging products must be established. Subsidised OWFs are, contrary to unsubsidised OWFs, protected from price risk due to a support payment, but face the same volume risk as unsubsidised OWFs in an OBZ

The key risks for OWF developers in an OBZ market setup relate to **market risks**, with key differences between unsubsidised and subsidised OWFs. In an OBZ, generation is generally higher than demand. The production of electricity from OWFs follows the wind profile, i.e., variations in wind speeds lead to variations in electricity production. The generated electricity volumes within an OBZ could, besides the volumes exported through available interconnector capacity towards adjacent BZs, also be balanced by offshore PtG in the OBZ. The possibility to trade across bidding zones in different electricity markets and to correct imbalances in the prediction of generation profiles, depends on the available transmission capacity between the different adjacent bidding zones.

In general, the average marginal production cost of electricity is lower within the OBZ compared to the onshore HM, but price levels are a result of market coupling[35]. This could ultimately lead to a less favourable business case for unsubsidised OWFs in an OBZ. Subsidised OWFs, in contrast, have support schemes in place (e.g., one-sided, or two-sided contracts-for-difference (CfDs)). For each electricity market (visualised and defined in Figure 5), the risks related to the OBZ are described below.

1. Forward markets

Forward markets are markets in which electricity is bought and sold for delivery at a future date. In forward markets, unsubsidised OWF face a flat price risk. Due to the limited amount of market participants within the OBZ, unsubsidised OWF may need to rely on forward markets outside the OBZ and (direct) power purchasing agreements (PPAs) to hedge the price risk. This results in a new locational basis risk for unsubsidised OWF, which emerges when a future is traded at a different location than the actual product. No impact is envisaged for subsidised OWF as they receive a support payment that compensates for the price difference between the settlement and forward price. If two parties want to conclude a deal across borders, they also need to acquire long-term cross-zonal transmission rights[36] that are auctioned on the Joint Allocation Office (JAO) platform[37].

Highlight
In forward markets, unsubsidised OWF face a flat price risk due to the limited amount of market participants within the OBZ.

[35] An OBZ setup may expose OWF developers to lower market revenues (compared to the HM setup) if the price in the OBZ converges towards the lowest price of one of the adjacent bidding zones, or when frequent curtailment of OWFs takes place to enable efficient import of negative price power.
[36] Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation. Link
[37] The JAO platform is a marketplace on behalf of TSOs for the auctioning of long- and short-term auctions of transmission capacity rights.

2. Day-ahead market

In day-ahead markets electricity is bought and sold for delivery the following day. Transmission constraints (as highlighted in section 2.1.1) can lead to an adverse, but limited, impact on liquidity for price formation in the day-ahead market. (Un)subsidised OWF can still make bids in a liquid day-ahead (DA) market, coupling almost all EU DA markets, but the market revenue is impacted by generation and scarce transmission capacity in and between the adjacent (onshore) bidding zones. In addition, financial losses related to curtailment or non-dispatch occur in situations where more electricity is generated than can be exported to adjacent bidding zones and consumed in the OBZ (volume risk), potentially resulting in lower electricity prices in the OBZ (interacting price/volume risk). Ex-ante congestion management and potentially advanced hybrid coupling (AHC)[38] can result in lost revenues for OWF developers due to a reduction in volume of electricity they can sell. Subsidised OWF are usually shielded from such price loss due to support schemes to ensure a certain level of guaranteed income for the electricity they produce.

Highlight
In the DA market, the market revenue in the OBZ is impacted by generation and scarce transmission capacity in and between the adjacent (onshore) bidding zones.

3. Intraday market

Intraday markets are markets in which electricity is bought and sold for delivery on the same day. Through the intraday market, buyers and sellers can adjust their order volumes in line with improved demand or renewable feed-in forecasts or unexpected power plant outages. On the intraday market in the OBZ, there is likely a limited number of bids. However, due to increased cross-border trading capacities, internationally accessible bids may increase, but limited trading opportunities are present after gate closure time (usually 60 minutes before the actual delivery of electricity[39]). It is currently not clear which of these two effects will dominate.

4. Balancing markets

Balancing mechanisms ensure the (physical) stability of the grid and rely on multiple parties within the OBZ to provide balancing service. From a system perspective, balancing an OBZ should not be considered much different than balancing of an existing bidding zone. Windfarms contribute to energy production in the OBZ and can provide the OBZ with down-regulation bids, when needed. In balancing markets, price risks emerge as an OBZ includes fewer counterparties that are available to correct any imbalances caused by the OWF. Forecast errors of generators in the OBZ have the same direction as they are caused by the connected wind farms in the OBZ that have correlated generation profiles. This results in an amplification of balancing deviation. *The requirement of clear balancing mechanisms*, which is currently lacking, is a regulatory risk. That is, the current lack of certainty regarding the possibility of entering bids into the EU balancing platforms is a regulatory risk that may affect the balancing framework for OWFs in an OBZ. The price of balancing services depends on available transmission capacity to adjacent bidding zones and the integration of the OBZ in the EU balancing platforms.

Highlight
Balancing an OBZ should not be considered much different than balancing an existing bidding zone.

[38] For further information on AHC, please see ENTSO-E - Assessing Selected Financial Support Options for Renewable Generation. Link
[39] ACER adopts a decision on intraday cross-zonal gate opening and closure time, May 2018. Link

Other risk drivers

Discrete changes to demand or supply in the OBZ will have a greater impact on the price level in smaller bidding zones like the OBZ, compared to larger bidding zones likes the HM bidding zone. For example, lower than expected offshore demand or interconnector availability can have a direct impact on the price level.

Figure 6: Example of technical unavailability of PtG asset.

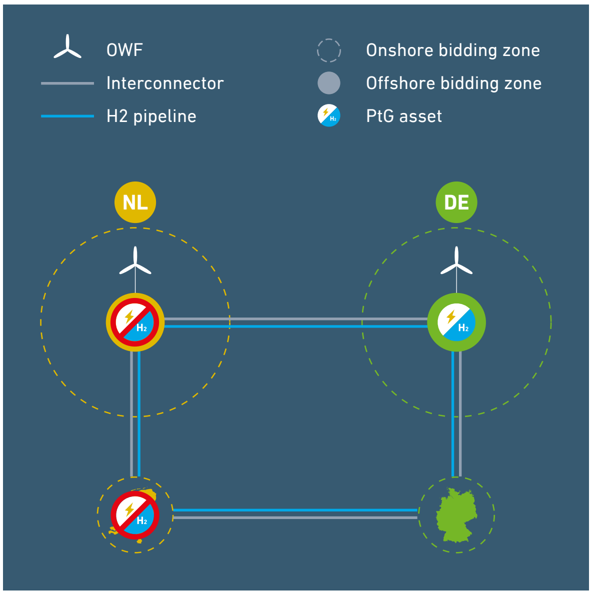
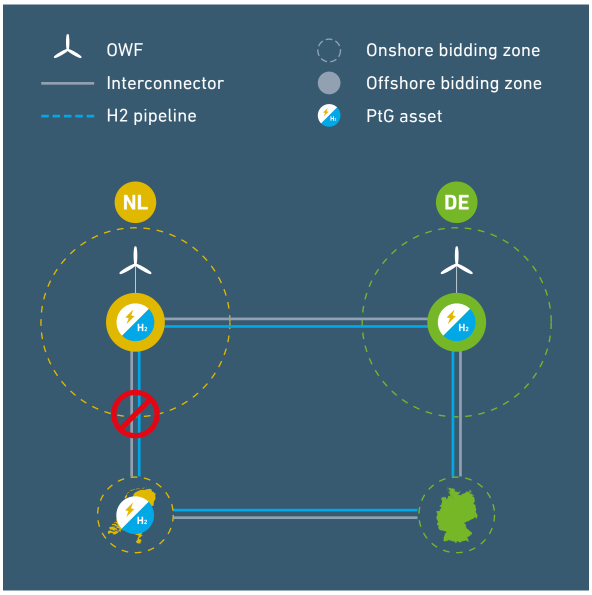


Figure 7: Example of technical unavailability of the connection to shore.



The *unavailability of load assets* (PtG) in the OBZ introduces a market risk, see Figure 6. In the situation that on- and offshore PtG assets are unavailable, an incremental price risk is introduced due to the dependency on the bidding of load assets and how much these assets are willing to pay for electricity generated by the OWF. Moreover, there is an incremental volume risk as the OWF might not be able to sell all its generated electricity due to congestion. In addition, if there is a long-term agreement in place between an unsubsidised OWF and a PtG asset in the OBZ, a lasting unavailability of a PtG asset can result in a *counterparty risk* for unsubsidised OWF developers.

A technical *unavailability of the connection to shore* introduces a volume and price risk. In Figure 7, the NL OWFs can only sell electricity through other OBZs now. The OWFs might receive compensation for the lost income, but level of compensation is uncertain. If export restrictions are in place, this could lead to curtailment of offshore wind energy. Prices in the DE OBZ will also be lower due to fewer export opportunities. An administrative national policy is unlikely to be able to mitigate this.

The volume of renewable electricity that can be transported could be affected by the available offshore PtG and interconnector capacity to adjacent bidding zones. In both the HM and OBZ market setup, ex-ante congestion management is applied, which is subjected to the result of market coupling. The price of electricity within an OBZ decreases when export capacity is unavailable or limited as generation will exceed demand. However, it is necessary to quantify this pricing effect through an assessment of the AHC to determine the direct nature of this relationship. Generated electricity by subsidised OWF is similarly reduced, but the price received by the OWF is unaffected due to the support payments. If there is a technical unavailability (due to an outage or maintenance) or a delay in the commissioning of the connection to shore, volume and price risks may occur due to export restrictions to adjacent OBZs. This could result in less generation and fewer export opportunities for the OWF.

2.3 Key risks for power-to-gas developers

Text box 7: Key messages

- Regulatory risks for PtG developers mainly exist in the early stages of the project with regulation on green hydrogen currently being negotiated between the European Parliament, European Commission and European Council.
- The risks for PtG developers (onshore/offshore) regarding electricity input, mirror those of the risks for OWF developers. Locating PtG offshore could be a mitigation for some risks faced by OWF developers as offshore assets do not face restrictions with respect to the export cable capacity and do not face regulatory uncertainty with respect to procuring green electricity.
- PtG risks relating to hydrogen supply do not change between HM and OBZ.
- Irrespective of the offshore electricity market setup, at the time of writing PtG producers face risks concerning the to be accepted regulatory framework and the market setup for and classification of green hydrogen.

The key risks for PtG developers relate to **price, volume and regulatory risks**. The differences in key risks between on- and offshore PtG developers are described below. The risks are categorised between *output* and *input* risks. Input and output risks refer to the potential uncertainties or vulnerabilities that can affect the inputs (electricity required for hydrogen production) or outputs (selling green hydrogen) or resources that are used in a process or system.

Output related risks

There are several risks related to selling green hydrogen (i.e., output). At the time of writing, the EU hydrogen and decarbonized gas market package[40] and the Delegated Act on additionality[41] have been proposed by the European Commission and are being discussed within and between the European Commission, Parliament and Council, further clarifying the regulatory (market) framework for renewable hydrogen.

Highlight
There is considerable uncertainty around the price of green hydrogen that consumers are willing to pay because the value of green hydrogen is not appropriately remunerated.

This introduces price risks:

- There is considerable uncertainty around the price of green hydrogen that consumers are willing to pay because the green value of hydrogen is not appropriately remunerated[42].
- Due to a potential lack of liquid markets for green hydrogen in the first years of the business case, PtG producers may need to rely on bilateral offtake agreements (PPAs) with green hydrogen consumers.
- The business case for green hydrogen is currently driven by regulation and not (yet) by the market. Hence, support schemes for PtG operators, in line with regulation, are an important determinant of the price of green hydrogen. There is uncertainty regarding the level of subsidy and applicable conditions, as these are still to be decided by policy makers.

These risks apply equally regardless of PtG being located in a HM or OBZ setup.

Input related risks

There are several risks associated with the procurement of renewable electricity for PtG operators (i.e., input). PtG assets are exposed to flat price risk, risks related to interactions between price and volume risk, and risks related to the unavailability of the PtG asset (operational risk).

Price risk can exist in case a PPA price is linked to the wholesale day-ahead market price. If an OBZ market setup is applied and the price is linked to the day-ahead market, offshore PtG will likely operate with lower electricity price levels compared to an onshore PtG operator. However, an OWF developer aims to sell electricity at the highest price levels, conflicting with the interest of offshore PtG developers.

Highlight
There are several risks associated with the procurement of renewable electricity for PtG operators.

The technical unavailability of PtG assets, due to, for example, outages or maintenance, can introduce a *price risk* for on- and offshore PtG developers. In case of unavailability of the asset, PtG developers are expected to resell their procured renewable electricity in electricity markets including the day-ahead and intraday market. There is an incremental price risk, as the price achieved in the OBZ setup is directly affected by the lower demand due to unavailable PtG assets. The risk borne by offshore PtG developers is higher than for onshore PtG developers due to an increased counterparty risk that comes with long-term agreements. An example of a counterparty risk is the likelihood of an offshore

[40] Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal markets for renewable and natural gases and for hydrogen (recast), Dec 2021. Link

[41] COMMISSION DELEGATED REGULATION (EU) of 10.2.2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin. Link

[42] However, the recast of the Renewable Energy Directive (RED II) provides binding targets for the uptake of Renewable Fuels of Non-Biological Origin (RFNBOs) which increase demand for hydrogen with at least 70 percent greenhouse gas (GHG) savings relative to grey hydrogen amongst EU Member States.

PtG producer not being able to resell their procured electricity (e.g., if no transmission capacity is available to an adjacent BZ). This price risk is not applicable for onshore PtG developers as they can still do portfolio management (re-sale of electricity) after intraday cross-zonal gate closure time (IDCZGCT) in some markets, like in the Netherlands and Germany.

Volume risk | Further, on- and offshore PtG developers are exposed to a *volume* risk if they are not able to resell the excess of renewable electricity inflicted by the unavailability of the PtG asset. The exposure to this volume risk is lower for onshore PtG compared to offshore PtG, as explained under the example for price risks for PtG developers. However, this risk is present irrespective of the market setup.

Curtailment risk may arise in a situation where an OWF is unable to deliver the contracted amount of electricity to the PtG developer due to e.g., a technical failure or transmission constraints. For offshore PtG developers, more options are available to procure lost volumes of green electricity in the wholesale markets as the electricity produced within an OBZ would automatically classify as green electricity under the current the EU Delegated Act.

For onshore PtG, in contrast, transmission constraints on the interconnector between the OBZ and the adjacent onshore bidding zone could result in a volume risk if insufficient green electricity can be exported to the onshore bidding zone. The severity of the related volume risks depends on the temporal correlation as set out under the Delegated Act as pointed out in section 2.1.2. Under the Delegated Act, temporal correlation for hydrogen to be certified as green will change from a monthly to an hourly correlation from 2030 onwards. The correlation is based on physical production, and thus results in a limited risk increase with a change from a HM to an OBZ market setup. In addition, from 2028 onwards, additionality for onshore PtG imposes further risks in case of technical unavailability or a delay in commissioning of an interconnector with the OBZ.

Highlight
Under the Delegated Act, temporal correlation for hydrogen to be certified as green will change from a monthly to an hourly correlation from 2030 onwards.

Regulatory risk | In relation to transmission constraints, the technical unavailability of a connection to shore introduces a *regulatory risk* specifically for onshore PtG developers. Electricity taken from the grid may no longer be certified as 'green' based on the criteria set out in the Delegated Act. Moreover, relevant particularly for the onshore PtG is the compliance with the additionality criterion of the Delegated Act which requires, among others, that the RE plant has not received operating or investment aid (Article 5 (b)). Should renewable energy power plants, including OWFs in an OBZ, prefer public support over PPAs with a PtG developer, this could be a risk for onshore PtG which might have limited options to find a counterparty with attractive prices/ conditions to enter into a green PPA. To which extent the renewable energy power plants will enter into public support schemes in the future is uncertain and depends among others on the electricity and hydrogen prices as well as the design of the support scheme. Therefore, the resulting risk for onshore PtG is not clear.

3 Mitigation measures

Text box 8: Key messages

- There are three low-regret mitigation actions that can readily be implemented by policy makers that may already be in place:

  1. Developing a compensation scheme for OWFs in an OBZ to address delayed commissioning and technical unavailability of transmission infrastructure.
  2. Increasing transparency and the understanding of the allocation mechanism for interconnector capacity.
  3. Developing offshore development plans (binding and non-binding) to provide insight into expected OWFs, PtG and interconnection capacities affecting an OBZ.

- Other mitigation measures such as financial transmission rights, contracts for difference, etc. could reduce volume risks associated with the impact of market coupling.

- An integral approach or commitment that deals with all sources of unavailability and across borders might be required. Should it be deemed necessary, support schemes remunerating the OWFs for their availability rather than actual production could be an option for protecting investors from both price and volume risks making revenue streams more predictable and thus, de-risking investments in hybrid offshore projects.

- As changes in capacities (electricity generation, interconnectors, PtG) can have a major impact on OBZ price risks, providing a degree of certainty on installed capacities in the OBZ, especially for the first years of the roll-out, ensures that investors benefit from protection in the years most valuable to the business case while recognising the flexibility required by TSOs and governments to adjust over time.

- Joint tendering of OWFs and PtG could be an option to reduce the risk of coordination failure, resulting in a reduction in price and volume risk faced by the OWF and PtG assets. However, this measure would increase the risk of a central planner imposing outcomes that might be different from market outcomes.

This chapter presents possible mitigation measures that can address the key risks for OWF developers in an OBZ as identified in section 2. Mitigation measures for PtG will not be discussed since the main risk faced by PtG assets is of regulatory nature and relates to proof of hydrogen green attribute. However, there needs to be certainty with respect to legislation on green hydrogen and on how network tariffs apply in an OBZ.

The discussed mitigation measures were divided into five topical categories and evaluated based on a set of criteria.

3.1 Overview of mitigation categories

Text box 9: Broad categories of mitigation measures

1. Low regret measures
2. Mitigation measures to address volume risks
3. Mitigation measures to address price risks
4. Mitigation measures to address price differences (spread between the OBZ and onshore markets)
5. Guaranteed offtaker

Mitigation measures that could be applied to the key risks for OWF developers (as identified in section 2) can be specified along five categories. These five categories include multiple measures to either fully mitigate the identified risks or to reduce risks to an acceptable level which can be transferred to and managed by appropriate stakeholders. However, the allocation of risk to different stakeholders is ultimately a political decision.

The sections below provide an outline and description of these broad categories of mitigation measures. Each mitigation measure is described and assessed according to the assessment of the risk they can address, the level of risk reduction they can establish, the regulatory intervention required to implement the measure, the practicability of the measure and the distributional effects and future proofness of the measure.

Text box 10: Assessment of mitigation measures

The mitigation measures are assessed in accordance with the following criteria:

1. **An assessment of risk |** extent to which the measure allows market participants to assess the risk, and potentially price it in if not fully mitigated.
2. **Risk reduction |** extent to which the measure is suited to deal with the risk it is supposed to tackle.
3. **Regulatory intervention |** if and how much regulatory intervention is required for the implementation of the mitigation measure. It also includes possible conflicts with other regulation.
4. **Practicability |** complexity of the implementation and use of the mitigation measure.
5. **Distributional effect |** the difference of impact across stakeholders affected by a mitigation measure.
6. **Future-proofness |** extent to which the mitigation measure is suitable in future hybrid projects and energy systems.

3.2 Low-regret actions

A number of low-regret actions are identified to allow stakeholders to better understand the risks they potentially face. These include:

1. Developing administrative compensation schemes to address:
   a. Technical unavailability of electrical infrastructure, and/or
   b. Delayed commissioning of electrical infrastructure;
2. Transparency and understanding of the allocation mechanism for interconnector capacity, i.e. this includes simulations and projections made available by the TSOs to allow for an assessment of the risk (and understanding/predictability of the algorithm to stakeholders);
3. Offshore development plans (binding or non-binding).

Low-regret measures yield large benefits under relatively low overall risks. A detailed description and assessment of each measure based on the aforementioned criteria (see section 3.1) is provided below.

3.2.1 Administrative compensation mechanism to deal with a delay in commissioning or technical unavailability of the interconnectors

OWFs depend on the availability of interconnector capacity to export electricity to shore. Technical unavailability occurs due to maintenance or outage of the interconnector. In certain European markets, TSOs are responsible for the delivery and maintenance of the grid connection and not the OWF developers. Absent of further regulation, the revenue loss due to the unavailability of the interconnector for the TSO relates to a delayed inclusion in the regulated asset base (RAB[43]) and the loss of congestion income from not being able to trade electricity across the interconnector.

Highlight
Unavailability of the interconnector can occur during commissioning (e.g. delays) and operation (e.g. maintenance and outages).

Administrative compensation schemes (ACS)[44] between OWFs and the TSO (or backed by the government) could provide OWF developers contractual clarity about potential compensation, the conditions of the ACS as well as the likelihood of occurrence for unavailability of interconnectors in case of a delay in commissioning[45] or due to technical unavailability of the interconnector. Current ACS are set up for radial connections, e.g. referring to the price of the national bidding zone rather than the price that would be achieved in the OBZ[46]. The ACS in case of an OBZ needs to detail the counterfactual prices.

Compensation is unlikely to be fully mitigating the risk, e.g. some risk could be shared with OWFs and force majeure clauses remain likely. Moreover, the unavailability of interconnectors can also affect adjacent OBZs. The compensation schemes are unlikely to cover spill-over effects to other jurisdictions. This could potentially be mitigated by integrated approach across countries, but might be politically difficult to achieve.

[43] Regulated Asset Base (RAB) is an assessment of adequacy and efficiency of a company's proposed investment program for the forthcoming regulatory period.
[44] Already in place for radial OWFs.
[45] The delay of interconnection infrastructure may also be due to a delay in the permitting process with no or limited control by the TSOs.
[46] Policy choice whether compensation comes from TSO and tariff payers, or from government and taxpayers. E.g. § 17e EnWG in Germany; Besluit schadevergoeding net op zee in the Netherlands; In Denmark network connections are mostly financed by OWF.

The degree of regulatory intervention needed for the implementation of this mitigation measure is limited and there is precedent with radial connections. Consideration, however, needs to be given to the definition of the compensation scheme as OWF developers in the OBZ do not have a priority access rights to the interconnector.

Highlight
For the commissioning of HVDC-lines the TSOs carry a substantially larger risk compard to point-of-connection assets.

Determining the right counterfactual might be challenging and double-counting with other potential mitigation measures like FTRs needs to be considered. The future-proofness of an ACS might become more complex with meshed grids[47] due to an increase of market parties and countries involved, with multiple contractual agreements.

In addition, it is important to note that a compensation scheme to mitigate the risk of a delay in commissioning may carry very high risks to TSOs. For example, risks for TSOs differ greatly between delays in commissioning of point-of-connection assets compared to delays in commissioning of HVDC-lines, with the latter carrying much larger risks. Such a compensation scheme must therefore carefully consider the appropriate risk transfer, taking into account events and permitting processes with no or limited controllability by the TSOs.

3.2.2 Transparency and understanding of allocation of interconnector capacity

OWFs depend on the availability of interconnector capacity to access onshore markets. The amount of capacity allocated to the interconnectors is a result of market coupling. The market coupling algorithm aims at maximizing social economic welfare in Europe. However, the method used to perform the market coupling calculations might impact the amount of capacity allocated to the interconnector. The difference in the methods can be explained by how well the grid is represented in the optimization algorithm. A better representation of the electricity grid leads to more accurate grid constraints but also a complexer optimization problem. Nevertheless, more a more accurate representation of the grid leads to achieving more social economic welfare.

Currently, three methods are used or have been used in Europe to perform the market coupling calculations. As these calculations are complex, and cover many EU electricity markets, the results are not always intuitive. *The Net transfer capacity (NTC) is a simplification of the grid and its physical characteristics and therefore not able to consider physical network restrictions.* The other approaches are more complex as they work with a more accurate representation of the physical grid and calculations are partly performed during market clearing. Market participants that were interviewed refer to *flow-based market coupling* and *advanced hybrid coupling* as a black box, making it difficult for OWFs and PtG developers to assess the availability of interconnector capacity and hence the level of OWF curtailment and price formation in the OBZ.

Highlight
Increasing the transparency and understanding of the allocation mechanism for interconnector capacity removes uncertainty for OWF and PtG developers to assess the risks.

Although there might be a limited direct effect of increasing the transparency and understanding of the allocation mechanism for interconnector capacity, it removes uncertainty for OWF and PtG developers to assess the risk they are ex-

[47] Meshed grids refer to clusters of OWFs connected to offshore hubs which are interlinked and connected to multiple countries.

posed to. Transparency can, for example, be provided by sharing further studies on the behaviour of the more complex methods for market coupling, simulations that resemble a planned hub (ex-ante)[48], timely and user-friendly disclosure of allocated interconnector capacities, and further disclosure and interaction with market participants when results are unexpected (ex-post).

The introduction of flow-based market coupling did not directly increase transparency; therefore, a market consultation could be proposed on how transparency can be increased through advanced hybrid coupling (AHC)[49]. AHC should ultimately improve the overall efficiency of the hub-and-spoke projects and lead to less ex-ante congestion management.

Highlight
Offshore development plans can provide clarity and certainty on future capacities (demand, supply and interconnectors) that should be expected by developers and other market parties and therefore allow them to better assess long-term market risks.

3.2.3 Offshore development plans (binding/non-binding)

Offshore development plans provide indications to developers on future developments that may affect the OBZ and allow them to better assess long-term risks. Similarly, guidance and principles on how the offshore electricity grid and hydrogen grid will develop will provide helpful indications. In an OBZ, the number of market parties involved in generation and demand is much smaller compared to a HM setup. Any changes might therefore result in greater risks for OWF and PtG developers. Offshore development plans can provide clarity and certainty on future capacities (demand, supply and interconnectors) that should be expected by developers and other market parties and therefore allow them to better assess long-term market risks. However, binding plans might reduce flexibility to adapt plans to new (unforeseen) circumstances and innovations.

This measure requires little regulatory intervention since offshore development plans are already produced by multiple governments across the North Sea area. Existing practices include national targets for offshore wind and electrolyser capacity, joint non-binding targets, such as under the NSEC, national offshore grid development plans, ENTSO-E and ENTSO-G TYNDPs and ONDP[50], and maritime planning.

3.3 Mitigation measures to address volume risks

Dependency of OWF developers on interconnector capacity is a key difference from the HM market setup and is a risk that stakeholders cannot manage themselves. Mitigation measures that deal with the delay in commissioning and technical unavailability as directly as possible are considered of high importance by OWF developers. Other mitigation measures addressing volume risks could be:

Highlight
Dependency of OWF developers on interconnector capacity is a risk that developers cannot manage themselves.

1. **Firmness commitments** are commitments by either TSOs or governments that a certain volume of electricity can be exported to shore over an interconnection, including financial compensation if the commitments are not met. This "commitment" is a broad concept, and there are various forms of such commitments possible.

[48] In the implementation phase of a reconfiguration of a BZ parallel runs of market coupling could help to better understand the impact on prices and allocated interconnector capacities (parallel runs were undertaken when implementing the reconfiguration of the German/Austrian bidding zone).
[49] AHC makes it possible to consider limitations of an meshed AC grid, while the effective HVDC interconnector capacities are addressed individually; but will affect market prices, and therefore affect the revenues for both OWF developers and TSOs (ENTSO-E - Assessing Selected Financial Support Options for Renewable Generation). Link
[50] The offshore network development plans per sea basin will be developed for the first time by January 2024 as required by the Trans-European Networks for Energy Regulation (TEN-E) (EU) 2022/869.

2. **Transmission Access Guarantees (TAG)**[51] are a compensation mechanism to compensate OWF developers for a reduction of transmission capacity of an interconnector due to congestion management by TSOs.
3. **Priority availability to OWF developers** to an interconnector implies providing a higher dispatch priority to OWF on an interconnector than for transmission between BZs. Note that priority availability of the interconnector is not the same as priority access to the interconnector by OWFs.

Administrative compensation schemes (ACS) and transmission access guarantees (TAGs) have desirable elements for OWF developers, but an integral approach or commitment that deals with all sources of unavailability across borders is regarded beneficial to OWF developers in an OBZ. Implementing a measure that does not directly interfere with existing electricity market regulation is preferable. However, all stakeholders who were interviewed requested some form of mitigation, but there was no clear preference for any of these instruments. The following sections detail each of the above measures.

Highlight
All stakeholders who were interviewed requested some form of mitigation, but there was no clear preference for any of these instruments.

3.3.1 Firmness commitments

Mitigation measures related to the firmness of interconnection capacity mainly address technical risks stemming from a delay of the commissioning of an interconnector, technical unavailability (outages) of the interconnector and reduced capacity made available to the market. Firmness commitments are a broad concept aiming at (partially) mimicking the operational behaviour of OWFs under a HM setup. Various forms of such commitments are possible, including Transmission Access Guarantees or transmission rights, which are described as a separate measure in the next section. Firmness commitments can be made by either TSOs or governments and entail a commitment that either generated electricity can be exported to shore, or, that a financial compensation is due. These commitments can address technical and curtailment risks which are associated with volume risks.

Firmness commitments can create risks for TSOs as they are required to provide a committed level of transmission capacity or compensation to OWF developers. Significant intervention could be required to introduce such commitments. In addition, offering firm interconnector capacity essentially creates discrimination between the different grid users in favour of the OWF developer.

Implementation of the measure might be challenging as calculations of the value of lost electricity might be complex and needs to be transparent. Wider redispatch policy and compensation schemes for technical unavailability can serve as models or templates for similar policies in other contexts. The measure is likely to introduce additional costs for TSOs, network users or the government. It is foreseen that a combination of TSO and government will be best able to deal with the risk. However, the risk is associated with the location of generation and load.

Highlight
Significant intervention will be required to introduce firmness commitments as it creates discrimination between the different grid users.

[51] A proposal from COM to support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market. Link

Concluding, firmness commitments can help reduce volume risks for developers by providing assurances and financial protections but introduce risks to TSOs and constitute a major intervention. Furthermore, this mitigation measure would also stroke against one of the fundamental principles of the internal European electricity market, namely, to provide a non-discriminatory market.

3.3.2 Transmission Access Guarantee

A transmission access guarantee is a mechanism to compensate OWF developers for a reduction of transmission capacity due to preventive congestion management by TSOs[52]. The TAG is developed for setups where the hybrid system is designed in such a way that the entire wind production can structurally be exported onshore and also features no zonal uncertainty. The TAG is effectively a CfD with a variable strike price at a particular time for all available volume. As such, it isolates the OWF from any of the risk relative to the HM approach, in which the OWF would have an injection capacity for which it has guaranteed access to the HM.

Under a TAG, a TSO would be responsible to compensate the OWF for restricting network actions. Compensation payments could be calculated based on the missed-out revenue that an OWF would have obtained in the reference market (i.e. the OBZ). The compensation payment could be determined by the reference bidding zone price (onshore market) minus the offshore bidding zone price (≥0) multiplied with the total available offshore generation. The TAG has an underlying assumption that all *"hybrid system should typically be designed in such a way that the entire wind production can structurally be exported onshore"*. This assumption creates a risk of overcompensating OWF developers, depending on the relative demand, generation, and interconnection capacities, in conjunction with the specifics on how the reference price is set[53]. Specifically, the underlying assumption is not in line with the overplanting of OWFs, i.e., it is economical to install more capacity than can be structurally exported, and OWF will self-curtail if required during a limited number of hours. Moreover, in cases in which two interconnectors are used to export all power, the choice of reference market becomes important to avoid overcompensation. Additionally, under the flow-based method, it is not the case that TSOs manage the allocated capacity as directly as today under NTC, and as such the effect of redistributing risks and incentives to TSOs is unclear. Finally, TAG does not consider the role of demand in an OBZ in the future, making the formulation of the instrument more difficult.

Highlight
TAG requires significant regulatory intervention and creates discrimination between different users of the interconnector if the commitment is only made to OWFs in an OBZ.

Similar to the interconnector firmness measure, TAG requires significant regulatory intervention and create discrimination between different users of the interconnector if the commitment is only made to OWFs in an OBZ. The TAG could be introduced as a new instrument in the OBZ market setup. No direct conflicts with existing legislation are present, but an amendment for the CACM (2015/1222) and Electricity Regulation (2019/943) regulations would be required. A challenge with its implementation is whether the available volume can be defined in a transparent manner and whether all produced electricity can be exported to shore.

[52] Support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market, August 2022. Link
[53] Please see the Appendix for examples of the TAG.

Concluding, transmission access guarantees could help reducing volume risks for developers by providing assurance that transmission capacity is available. However, they introduce differential treatment of market actors and create risks for TSOs, as congestion income may not provide adequate revenue for honouring guarantees. Furthermore, deviations from the assumption that all electricity can be exported to shore make the formulation of the TAG more difficult, as also the OBZ electricity price can be a relevant factor for compensation. This mitigation measure would also stroke against one of the fundamental principles of the internal European electricity market, namely, to provide a non-discriminatory market.

Highlight
The TAG would stroke against one of the fundamental principles of the internal European electricity market, namely, to provide a non-discriminatory market.

3.3.3 Priority availability for offshore wind farm developers

Another variant of firmness of interconnection is priority availability[54]. Prioritising access to an interconnector implies preferential access to an interconnector to ensure that capacity is available when needed. The rationale to grant priority access to OWFs could be that OWFs are more valuable to dispatch than the scheduling of interconnector flows (due to lower losses as distances are shorter). This allows OWF developers to operate as if there was a guaranteed capacity of the interconnector available to them. However, priority access might add another layer of complexity to the flow-based market coupling algorithm. As this was already difficult to fully understand by developers, this mitigation measure might lead to additional complexity in, for example, providing transparency of this measure. The exact application and design of this measure is unclear, and therefore not suitable for direct implementation.

3.4 Mitigation measures to address price risks

The electricity prices materialising in the OBZ are relatively sensitive to changes in the infrastructure and assets, such as the capacity of installed OWF, offshore PtG and interconnectors. Therefore, ensuring a balanced development of offshore generation, demand and interconnection is imperative to provide certainty for developers under any market setup. Such clarity mitigates flat price risk, and interacting price & volume risk. Mitigation measures identified to ensure a balanced development under an OBZ market setup are:

Highlight
Clarity on a balanced development of offshore generation, demand and interconnection can mitigate price risks.

1. **Joint tendering of OWF and PtG assets |** joint tendering of OWF and PtG to prevent situations in which one of the elements might not be profitable as a stand-alone investment and increase certainty on the planned capacities of OWF and PtG that will be commissioned.
2. **Increase of interconnector capacity at cost for OWF developers |** developers willing to contribute to an increased interconnection capacity of the interconnectors. This additional capacity will not be offered to the market, and is only available to the OWF developers. This increases their security of utilising the interconnector, hereby reducing the market risks in an OBZ.
3. **Binding commitments for future development |** providing indications to developers on future developments that might affect the OBZ as well as guidance and principles on the development of offshore grids. This allows developers to better assess long-term risks. Binding commitments or rules regarding the size of OWFs and their capacities within an OBZ, interconnectors

[54] Note that priority availability of the interconnector is not the same as priority access to the interconnector by an OWF.

to neighbouring BZs, could serve as mitigation measures against unforeseen changes that may occur after the initial roll-out[55].

The electricity price materialising in the OBZ is relatively sensitive to changes of the installed capacities of all the assets. As a consequence, the right balance needs to be struck between the dimensioning of the system; OWF and PtG capacities as well as interconnectors. The NSPWH has assessed three mitigation measures that aim to ensure a balanced OBZ development.

Text box 11: Mitigation measures to ensure a balanced OBZ development

1. Joint tendering of OWF and PtG
2. Additional interconnector capacity at cost for OWF developers
3. Binding commitments for future development

3.4.1 Joint tendering of offshore wind farms and power-to-gas

Joint tendering of OWF and PtG implies that both assets are developed and operated by a single party or consortium. Flat price risks are mitigated in this way as there is internal hedging of the electricity price between both assets; PtG developers are protected against high prices, OWF developers are protected against low prices.

Joint tendering reduces the risk of coordination failure, which can lead to a reduction of the flat price risk and interacting price/volume risk faced by OWF and PtG developers. However, this approach increases the risk that a central planner would make decisions that are different from efficient market outcomes. Concession agreements and conditions are required in any case. Joint tendering limits the optimisation possibilities for developers and may be a more significant intervention than other auction designs. Joint tendering is not difficult to implement administratively, but it requires a central planner to ensure the balance is right, rather than relying on market outcomes.

Highlight
Joint tendering of OWF and PtG involves ownership by a single party/consortium, which mitigates flat price risks through internal hedging of the electricity price between both assets.

Concluding, joint tendering does provide some further certainty to parties that the planned capacities of OWF and PtG will be commissioned, but this measure comes at a potential societal risk.

3.4.2 Additional interconnector capacity at cost for offshore wind farm developers

From the perspective of an OWF developer, investing in a larger interconnection capacity to shore which is reserved for them, increases the probability that generated electricity can reach BZs uncongested. This in turn would decrease the flat price and volume risks. A possible mitigation measure is to introduce flexibility in the interconnector capacity. This could be realised through enabling the

[55] An independent regulator should be put in charge for supervision and guaranteeing the targets being met.

OWF developer to request building additional capacity, provided the developer is willing to bear the cost.

OWF developers have an incentive to reduce volume and flat price risks, while TSOs pursue increasing societal welfare. It may be challenging to assess the distributional effects and determine whether additional capacity leads to increased societal welfare.

PtG developers are affected differently by increased interconnection capacity. Offshore PtG may face higher prices in an OBZ. This in turn could improve the competitive positioning of onshore PtG developers.

Highlight
PtG developers are affected differently by increased interconnection capacity. Offshore PtG may face higher prices in an OBZ.

The mitigation may introduce regulatory issues, in case an OWF developer expects priority access to interconnectors as a result of their financial contribution. This would be in conflict with non-discriminatory access principles. From the perspective of practicability, it will be challenging to define a mechanism that prevents free riding if there are multiple OWF investors in the OBZ.

Concluding, additional interconnector capacity at cost for OWF developers could help to reduce risks but increases uncertainty for demand in the OBZ and introduces a range of regulatory and practical issues.

3.4.3 Binding commitments for future developments

Binding commitments refer to targets related to the capacity of the OWF and PtG within an OBZ and interconnectors towards adjacent BZs. These commitments create a competitive environment for OWF and PtG developers by clarifying the conditions that drive prices and volumes. Binding targets could therefore significantly reduce flat price and the interacting price/volume risk.

However, commitments to specific technologies and locations are a significant policy intervention. They lock in choices and reduce flexibility for policy makers to make adjustments over time, which could be desirable (e.g., as changes in technology, the energy market or grid congestion occur). Firm commitments can be costly and lead to disputes between stakeholders within an OBZ.

Implementing binding commitments is administratively feasible, but there will be political and legal challenges in achieving this (e.g., getting political commitment to a long-term infrastructure plan, subject to uncertainty). In addition, binding targets could result in a suboptimal overall design of the OBZ.

Highlight
Altough binding commitments is administratively feasible, there will be political and legal challenges in achieving it.

3.5 Mitigation measures to address price differences between offshore bidding zone and onshore markets

Market risks, including the price risk and volume risk, related to the technical unavailability of interconnection or to the market coupling algorithm that allocates transmission capacity, could be alleviated through the introduction of the three measures provided below.

3.5.1 Financial Transmission Rights

Financial transmission rights (FTRs)[56] are a financial instrument that entitles the holder to receive the difference in price between the two connected markets for a defined amount of MWs and in a particular direction. In order to bring back the risk to the reference market approach, the transmission right is considered from the OBZ to the home market. FTRs are existing instruments provided by TSOs for various time intervals but are not yet offered for a period that would cover the lifetime of the OWF.

FTRs may also be important for subsidised wind farms if the subsidy price differs from the FTR. The discussion on FTRs focuses on how rights to an OWF are allocated and priced during the lifetime of the asset or concession.

The allocation of rights affects the value of the concession, and this allocation can shift value from TSOs to governments. There are two options for allocating rights: (1) including them in the concession auction, or (2) providing them in a separate process. The second option allows investors to manage price and volume risks but raises questions around whether investors will be able to acquire the rights and whether concessions will proceed if government subsidies are required.

The question of how many rights to allocate has two options. One option is to allocate all rights of the line to a matching firm injection capacity under the HM approach, which could "overcompensate" the OWFs. This option might be risky for the TSO as the concession auction is not available to all buyers and is of a one-off nature. The other option is to determine a number of rights based on risk expectation. The number of rights needed could differ for different parties and revealing this information in an auction would be the best option. A Contracts-for-difference (CfD) might be able to more directly deal with the potential volume at risk.

Subsidy leakage could be deemed an undesirable distributional effect. The financial transmission rights, as such, are available and require little intervention (apart from the time horizon required to implement the intervention). Regulatory intervention is required on the allocation of the FTRs, where it would clash with several principles and regulations (at a minimum Electricity market, forward capacity allocation (FCA), and CACM[57]).

[56] An FTR compensates congestion costs occurring on the day-ahead market between the OBZ and adjacent BZ. An FTR is defined as a right to transport energy from the point of injection to a point of delivery across an interconnector. For each hour that congestion takes place over this interconnector and this energy cannot be transported, the party with the FTR is awarded a share of congestion income collected in that specific hour.

[57] CACM provides the legal basis for the designation of nominated electricity market operators (NEMOs), outlines their tasks associated with market coupling and provides a framework for their cooperation with TSOs.

3.5.2 Contracts for Difference

Contracts for difference (CfDs)[58] are a support mechanism that can be provided to OWF. A CfD is a contract which pays the difference between an agreed strike price and a reference price of electricity (in this case the OBZ price) to an OWF developer. The strike price can be fixed (like in classical support mechanisms) or variable (in this case the price of the home market). The spread will be applied to the produced volume. Typically counterparties of a CfD are the government or the TSO. CfDs backed-up by governments qualify as a subsidy and are an evolving hedging tool with diverse designs. Traditional CfDs remunerate OWFs for the actual energy produced and can mitigate price risks but not volume risks. Alternative options, such as a CfD based on deemed generation in which OWFs are paid based on their potential to generate (availability) rather than their actual generation, can hedge OWFs not only against price risk, but also volume risk. The latter would de-risk investments for OWFs connected to hybrid projects. This type of CfD is effectively a capacity-based support scheme remunerating OWFs for their availability to serve the system. Recent studies by Newbery[59], ENTSO-E[60] and Schlecht, et.al.[61] propose CfD designs decoupling payments from actual production. However, the design of this instrument requires careful consideration in order to avoid any inefficiencies/risks.

Highlight
Contracts-for-difference (CfD) are expected to be able to more directly deal with the potential volume at risk.

A CfD captures the spreads and allows direct hedging in combination with more liquid onshore markets. Market parties do need to formulate expectations on the development of the OBZ to assess the value of the CfD. The regulatory intervention is high when CfDs are offered by the TSOs and they require compatibility with FTRs. In addition, government-backed CfDs are likely to qualify as subsidy.

If a CfD is based on actual volumes produced, the CfD appears to be practical as it requires a single contract from the day of commissioning of the OWF. A CfD would become more difficult to implement if it applies to all flows across the interconnector (like FTRs). This could lead to a situation in which produced volumes are subsidised under different subsidy regimes than where the actual volume is sold to. A CfD redistributes risks to a CfD counterparty, but this risk could be symmetrical depending on design of the contract. TSO-backed CfDs are essentially FTRs and in the long run, one instrument would be preferred. Ideally government-backed support schemes would be phased out to reduce societal costs.

3.5.3 Market maker

A market maker supports the exchange of liquidity directly and is given formal obligations to post bids and offers for a specific product or set of products. They satisfy demand to sell/buy at current market prices rather than wait for a better price, by offsetting the imbalance at the current market price and requiring a liquidity premium until the imbalance disappears.

[58] A contract (often qualified as support mechanism) which pays the difference between an agreed settlement price of electricity and the actual electricity price to ensure a guaranteed income level to a developer. In case the actual electricity price is higher than the agreed settlement price, the developer needs to pay back the difference again if a double-sided CfD is applied.
[59] The Energy Journal (iaee.org). Link
[60] ENTSO-E Vision: A Power System for a Carbon Neutral Europe. Link
[61] https://www.econstor.eu/handle/10419/268370. Link

Within the OBZ, there are only a limited number of parties with physical assets and positions. It is unlikely that liquidity will develop in the OBZ (bilateral contracts are more likely). The alternative could be a market maker that creates liquidity on the spreads between the OBZ and onshore market. Such trade can be based on the transmission rights, but could also be purely financial, reducing flat price risk. Brokers can also act as market makers on commercial terms, but market makers for onshore PtG are unlikely to be willing to deal with guarantees of origins (GoO) because there is limited spread in the onshore market.

Highlight
Mandatory market making requires significant oversight and regulation, while voluntary market making is practical and incentivised.

Market makers can be set up voluntarily or mandatory. Their level of trade and risk premia can provide a market benchmark. Mandatory market making requires significant oversight and regulation, while voluntary market making is practical and incentivised. Market maker activity is usually funded through e.g., the bid/ask spread, but in cases of low transactions they may be compensated through an exchange or a surcharge on end customers. The implementation and regulation of market making can be complex, including IT systems and cost allocation, and regulated market making may eventually be phased out.

Highlight
Stakeholders who were interviewed expressed mixed views on whether these instruments would need to be introduced over and above the use of FTRs.

Stakeholders who were interviewed expressed mixed views on whether market makers and CFDs would need to be introduced over and above the use of FTRs more generally, in addition to mitigations to deal with locational basis risk from the interconnector directly.

3.6 Guaranteed offtaker

Guaranteed offtakers, often a government supported entity, act as central buyers/sellers who commit to purchasing a volume of electricity or hydrogen and bring/sell it to the demand allowing for a clear assessment of remaining risks. In addition, they provide a reliable counterparty. Guaranteed offtakers, however, introduce regulatory risks and uncertainty at the end of the contract. This measure would isolate both OWF and PtG developers from most risks going beyond the HM setup. Moreover, it is a very interventionist measure where a government heavily interferes in the market and absorbs all the risks. The parties interviewed expressed little appetite for this mitigation measure.

Highlight
Having guaranteed offtakers, who act as central buyers/sellers to purchase a set volume of electricity/hydrogen, can minimize risks, but introduces regulatory uncertainty and requires regulatory intervention.

This measure might be more suitable for completely new technologies rather than introducing changes to the market setup for established technologies. Although a new organisation needs to be established to set up a guaranteed offtaker, governments have experience with auctions and roll-out schemes for hydrogen. In the long-term, the presence of a guaranteed offtaker is likely to be diminished, although recent calls for new market designs in the energy sector might mean there is more support for a government entity to become involved in the market.

4 Conclusions and recommendations

This paper aimed at providing an understanding of the impact of the market setup on investors in an offshore hybrid project by assessing the risks for investors in OWFs and PtG in a selected market setup (OBZ or HM). An overview of key risks and potential mitigation measures for these risks is presented. The analysis in this paper was refined by conducting interviews with a sample of developers and investors active in the North-West European electricity market. The interviews were conducted on an anonymous basis.

4.1 Key risks

The key incremental risks for OWFs in an OBZ versus HM setup are mainly driven by the relatively small bidding zone with correlated generation, given limited demand within the zone. This means that any incremental changes to the assets (e.g. size of load, generation and infrastructure) would have a greater impact on the price level in a smaller bidding zone like the OBZ, compared to the larger HM bidding zone. Moreover, the dependency on interconnectors under an OBZ is a risk that investors in OWFs cannot manage themselves. Potential congestion on the interconnector or technical unavailability or delay in commissioning of interconnectors would lead to increased price and volume risk, as well as interacting price/volume risk (the unavailability of one interconnector can lead to greater volumes towards other OBZs, depressing prices there given a certain interconnector capacity and OBZ demand). Whether these risks are detrimental to the business case of the investors is an aspect that needs to be further assessed.

Highlight
The key incremental risks for OWFs in an OBZ versus HM setup are driven by the relatively small bidding zone.

Offshore PtG faces mainly the mirrored version of the aforementioned risks, i.e., they can absorb volumes and benefit from changes in prices in the opposite direction (i.e., low price hours). Nevertheless, clarity on these risks is required for the business case. Onshore PtG relies on the interconnector capacity and its interest are more aligned with the OWFs, i.e., getting power to shore. The main incremental risk relates to the conditions for onshore PtG to procure green electricity (in line with EU Delegated Act on electricity use for production for green hydrogen).

4.2 Mitigation measures

An optimal risk allocation sees risks being borne by those actors that are able to efficiently manage them. How risks under an OBZ setup should be allocated is a political decision. In any case, **aligning measures to mitigate risks with policy objectives** is crucial in order to avoid unnecessary societal costs. This implies using the right measure to mitigate the directly corresponding risk.

Low-regret measures that help developers understand and better assess the risks they may face in a hybrid project under an OBZ market setup have been identified. This aligns with the views of stakeholders that were interviewed that first and foremost there is the need to be able to assess the risks. Administrative compensation schemes set up between OWFs and TSOs, similar to existing offshore radial connections, would provide contractual clarity about potential compensation for the technical unavailability or a delay in the commissioning of the interconnector between the OBZ and onshore BZ. Particular consideration, however, needs to be given to the definition of the compensation scheme, including defining the correct benchmark for technical availability, the specific risk to TSOs associated with delays in commissioning of HVDC-assets (especially when the delay of infrastructure is due to a delay in the permission processes with no or limited controllability by the TSOs), as well as the spill-over effects to other jurisdictions.

Increasing transparency on the available interconnector capacity and improving market participant's understanding of capacity allocation, particularly under the flow-based and advance hybrid market coupling, is crucial. Such transparency could be provided by further studies on the network representation in general, simulations that resemble a planned hub (ex-ante), timely and user-friendly disclosure of allocated interconnector capacities and further disclosure and interaction with market participants when results are unexpected (ex-post).

Highlight
Should the OBZ be implemented for hybrid offshore projects, it is recommended to apply the low-regret measures in order to allow stakeholders to better understand the risks they potentially face.

In addition, information on offshore development plans (binding or non-binding), such as planned interconnectors and additional build-out of OWF/PtG capacity, provide indications to investors on future developments that affect the OBZ and allow them to better assess long-term risks.

Dealing as directly as possible with risks of interconnector unavailability is considered as very desirable by interviewed stakeholders. OWFs in an OBZ depend on the availability of interconnector capacity to export electricity to shore and this is a risk that developers are unlikely to be able to manage themselves. As mentioned above, administrative compensation schemes are desirable by stakeholders to reduce risks stemming from technical unavailability or delays in commissioning of interconnectors. Other mitigation measures such as FTRs, CfDs, etc. could reduce volume risks associated with the impact of flow-based market coupling. However, interviewed stakeholders did not express a clear preference for one particular instrument.

The aforementioned mitigation measures have desirable elements, but an integral approach or commitment that deals with all sources of unavailability and across borders might be required. To this end, support schemes remunerating the OWFs for their availability rather than actual production could be an option to protect investors from both price and volume risks making revenue streams more predictable and thus, de-risking investments in hybrid offshore projects. The need for public support should be revealed and determined in a transparent way i.e. through auctions for offshore wind. It is noted, that implementing a measure that does not directly interfere with existing electricity market regulation is preferrable.

Providing stability for the development in the first years of the roll-out is crucial. Providing a degree of certainty on installed capacities (electricity generation, interconnection, PtG) in the OBZ for the first years of the roll-out ensures that investors benefit from protection in the years most valuable to the business case, while recognising the flexibility required by TSOs and governments to adjust over time. This balances the interests of investors for a balanced and stable development of the OBZ with the interest for a rapid roll-out of offshore wind.

To this end, joint tendering of OWFs and PtG assets could be an option to reduce the risk of coordination failure, resulting in a reduction in price and volume risk faced by the OWF and PtG assets. However, this measure would increase the risk of a central planner imposing outcomes that might be different from market outcomes. The stakeholders that were interviewed requested that indeed some parameters (electricity generation, interconnectors, PtG) would need to be fixed given the small size of the OBZ, but at the same time stressed that within certain parameters, the market would be able to deliver efficient outcomes with limited need for further coordination.

Highlight
Joint tendering of OWFs and PtG assets could be an option to reduce the risk of coordination failure, resulting in a reduction in price and volume risk faced by the OWF and PtG assets.

4.3 Recommendations to policy makers

Should an OBZ market setup be implemented for hybrid offshore projects, NSP-WH would recommend policy makers to apply the identified low-regret measures in order to allow stakeholders to better understand the risks they potentially face, hereby increasing investment security. If there are remaining risks that are detrimental to the business case of OWFs, these should be revealed in a transparent way e.g., through auctions for offshore wind. These auctions would determine the need and level of support for OWFs. If deemed necessary, a support scheme that covers remaining volume and price risks could be implemented.

Mitigation measures should be designed in a way that aligns with the policy objectives, i.e. if the objective is to de-risk investments in offshore wind, then an instrument should be designed that serves this specific purpose. In this way, unnecessary societal costs are avoided. Additionally, mitigation measures should follow the guiding principles of the EU internal market, including the principle of non-discriminatory treatment. Any mitigation measure should therefore be subject to competition and made available to all market participants.

Finally, due to the multinational playing-field of hybrid offshore projects, there are certain aspects that require particular attention from policy makers. These include the impact of the long-term roll-out strategy and the certainty around this, which impacts the price and volume risk. Moreover, attention is needed to assess the impact of possible mitigation measures in one OBZ affecting neighbouring OBZs (spill-over effects). The design of an OBZ is subjected to its national policies. Potential mitigation measures affect flows to and from other OBZs, potentially increasing or decreasing prices in other OBZs. For example, the unavailability of one interconnector can lead to flows towards other OBZs and depress prices there. This could potentially be mitigated by an integrated approach across countries, but this is a matter of political will.

Highlight
Risks that are detrimental to the business case of OWFs, should be revealed in a transparent way (e.g., through auctions for offshore wind).

Appendix

Other risk categories for developers

Other risk categories that are present for OWF and PtG developers (section 2.1), regardless of the market setup, are provided with a description below.

1. Strategic/business risks
Strategic/business risks refer to risks associated with approval and permitting processes for the development of OWF and PtG projects across Europe, and the risks related to increasing exposure to changing business conditions. Business conditions include:
- Changing financial conditions[62]
- Available technologies
- Innovations

Other strategic risks include:
- Insufficient available technical expertise and personnel
- A lack of public acceptance of the developed solution/technology

2. Credit risk
Credit risk includes the possibility of losses from a counterparty's failure to reimburse or meet contractual obligations, including settlement- and replacement risk. Settlement risk means that one of the parties does not deliver on the terms of a contract, e.g., the offtaker in a power purchase agreement fails to pay the generator. Replacement risk is the possibility that a default in a contract between two parties can lead to having to replace a sale at a different price than the original contract.

3. Operational risk
Operational risk is an umbrella concept for risks that can incur costs separate from the market risk, including technical, construction and operation costs of the OWF or PtG installations and electrical or hydrogen infrastructure. These costs can increase or decrease due to (un)foreseen changes to the allocation of costs and risks between parties. These events include for example, unplanned failures during the operational lifetime, or cost increases for maintenance work due to increasing fuel prices.

The *operational cost risk* refers to the variable cost of operating a PtG asset. This risk is relevant for offshore PtG producers in an OBZ. Costs for balancing services for PtG operators in an OBZ can potentially be higher due to transmission constraints and lower availability of balancing responsible parties[63] (BRPs) for balancing capacity compared to onshore BZs. Other examples include uncertainty regarding the allocation of offshore network costs, or higher network tariffs in case a separate network tariff is used for the OBZ covering the offshore network costs.

4. Liability and legal risks
Liability and legal risks include damage to third parties and discrepancies between laws, regulation, and standards. Third party risk can include liability due to ecological damage and bodily injuries, while examples of discrepancies may include a conflict between national and international (e.g., EU) law.

[62] PtG assets cannot classify their volumes of hydrogen as green if the procured electricity has received any operational or developing aid, posing risks to subsidised OWFs.
[63] A market participant that is responsible for ensuring that the electricity it consumes or produces is balanced with the electricity it receives or delivers to the grid.

Mitigation measures

Mitigation measures available to market parties to balance risks and four numerical examples for the Transmission Access Guarantee (TAG) are provided below.

1. Mitigation measures available to market parties to balance risks

In the absence of any constraints, balancing markets are de-facto coupled and there is no difference between the HM and OBZ. A first mitigation strategy is therefore to assess the amount of interconnector capacity to be made available for balancing purposes based on a cost benefit analysis (CBA). The impact of constrained situations varies. In general, whenever the OWF or OBZ in total are short[64], we would expect a coupling with onshore markets as interconnector (IC) capacity becomes available. However, the OBZ market setup makes it less predictable on which balancing market the OBZ balancing price is based.

When the OWF/OBZ is long[65], this might be offset against importing interconnectors. When all interconnectors are exporting and congested, there is no value in a long position. There is no portfolio effect from operating in a single (large) market. We have not identified an intervention that would serve as mitigation measure for this. Market parties should, however, be able to price in potentially higher costs or lower revenues from the balancing market. This would require further information on the balancing capabilities in the OBZ and on the interaction with the interconnectors.

2. Numerical examples Transmission Access Guarantee

Figure 8: Worked example A: sufficient export capacity to the host country

In this scenario, we have two onshore markets, A and B, with prices of €30/MWh and €50/MWh, respectively. The OBZ, which is located within the EEZ of country B, is also part of the reference market in the TAG. The available production in the OBZ is 1000 MW, which is transported to market B unless there is an unavailability of the interconnectors. Additionally, 200 MW will flow from market A to market B. The price in the OBZ is €30/MWh and the total revenues for OWFs are €30,000. If interconnector B is curtailed, 600 MW can still flow to market A, but the price in the OBZ drops to €0/MWh and the total revenues become €0. In this case, the TAG would be valued at (€50/MWh-€0/MWh)*1000 MW= €50,000. This value would overcompensate the OWF in relation to its exposure in the OBZ setup. However, it would result in payments similar to the HM approach, given that the OWF is exposed to OBZ pricing when there is a lack of availability.

[64] There is not enough electricity generated compared to what was offered to the market.
[65] There is too much electricity generated compared to what was offered to the market.

Figure 9: Worked example B: jointly sufficient export capacity.

In comparison to worked example A, we have modified the capacity of interconnector B while ensuring that all OWF production can still be exported. Country A is the marginal source of demand, and therefore sets the price at €30/MWh. Total revenues in this setup are €30,000. If interconnector B is curtailed, 600 MW can still flow to market A, but the price in the OBZ drops to €0/MWh resulting in total revenues of €0. In this case, the TAG would be valued at (€50/MWh-€0/MWh)*1000 MW= €50,000, which would overcompensate the OWF.

It is important to consider the reference market dynamically when determining compensation. While 500 MW of export capacity to market B was guaranteed, this amount at the price of market B would not fully compensate for the loss (500 MW* €50/MWh= €25,000/MWh). This factor should be taken into account when making any other form of "firmness commitment".

Figure 10: Worked example C: jointly sufficient export capacity including demand in the OBZ.

Compared to worked example B, we introduce demand in the OBZ, such as electrolysers with a willingness to pay €20/MWh at a certain price point in the hydrogen market. In the absence of unavailability, the electrolysers do not consume any electricity, and the marginal price remains at €30/MWh, resulting in total revenues of €30,000.

However, if there is unavailability of the interconnector, the electrolysers set the marginal price at €20/MWh, leading to total revenues of €20,000. Despite this, there is no volume loss for the OWFs since all volumes are sold. To determine the compensation, a comparison of both scenarios is necessary as the TAG would be valued at €30,000, which combined with the received revenues of €20,000 would result in overcompensation.

Figure 11: Worked example D: OBZ demand required to absorb excess wind capacity.

Compared to worked example C, we adjust the interconnector capacities to integrate OBZ demand into the configuration. The offshore demand becomes the marginal source of demand and establishes the OBZ price at €20/MWh, resulting in total revenues of €20,000. If unavailability occurs, there is excess supply, and the price and revenues drop to zero. The TAG pertains to country B and would have a value of €50/MWh*1000MW = €50,000, although it was not originally designed for this purpose. Since there is no observable price to determine appropriate compensation in the event of unavailability of the interconnector, the only available prices are €30 in A, €0 in the OBZ, and €50 in B. Therefore, the compensation of €20,000 can only be calculated based on an unobserved scenario.

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