The North Seas Countries' Offshore Grid Initiative

Discussion Paper 2: Integrated Offshore Networks and The Electricity Target Model

Deliverable 3 – Final Version

Working Group 2 – Market and Regulatory issues

31 July 2014

1. Introduction

1.1 Context

In 2010, the European Commission published its Energy Infrastructures Priorities for 2020 and 2030. The Commission identified the offshore grid in the North Seas as a priority corridor for the transport of electricity. In this context the North Seas Countries' Offshore Grid Initiative (NSCOGI) was formed to promote and facilitate coordinated development of a possible offshore network in the North Seas.

Since then, the development of an interconnected offshore grid in Northern Europe has been intensively discussed by the European Commission, governments, Transmission System Operators (TSOs), National Regulation Authorities (NRAs), and industries in the framework of NSCOGI. Meanwhile, several studies have investigated the benefits of an integrated offshore grid. Several studies came to the same conclusion: a meshed grid design would potentially bring financial, technical and environmental benefits at the European level.

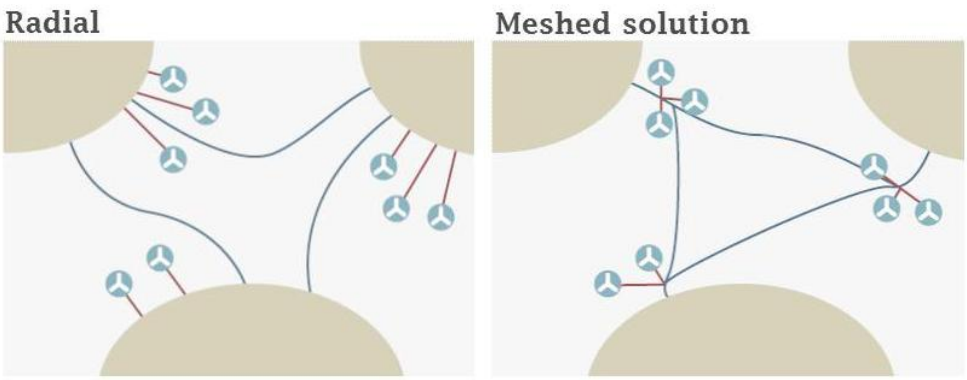

Figure 1 - Possible offshore grid development

1.2 Aims and Objectives of the NSCOGI

The aim of NSCOGI is to establish a strategic and cooperative approach to improve current and future energy infrastructure development in the North Seas. The initiative seeks to identify ways to facilitate coordinated development of a possible offshore network that maximizes the cost-effective use of the renewable resources and infrastructure investments in the North Seas.

The Memorandum of Understanding, signed on 3 December 2010, breaks down the overarching objective of promoting and facilitating the coordinated development of a possible offshore network in the North Seas into a set of deliverables, which are grouped into:

- Grid configuration & integration issues (Working Group 1 - WG1),
- Market and regulatory issues (WG2); and
- Permitting and authorisation issues (WG3).

Working Group 2 on market and regulatory issues was assigned a set of five deliverables:

- identification of incompatibilities of national markets and regulatory regimes which act as barriers to coordinated offshore grid development.
- recommendations on how to address these barriers so that national regimes are sufficiently compatible to facilitate cross-border investment.
- design of efficient cost-benefit sharing and investment incentives.
- recommendations on a common regulatory approach to anticipatory investments (including the sharing of technological risk) to achieve a cost efficient grid development.
- design of market mechanisms to facilitate the increased penetration of variable renewable generation and combination of offshore wind farms with interconnection, taking into account national renewables support schemes, to contribute to the elaboration of codes and guidelines under the Third Package.

Working Group 2 has already achieved and published several documents:

- Regulatory Benchmark (January 2012)
- Recommendations for guiding principles for the development of integrated offshore cross border infrastructure (November 2012)
- Possible Market Arrangements for Integrated Offshore Networks (March 2013)

Working Group 2 has identified the following further work areas to be pursued during 2014 and beyond:

- Finalise the work on developing options for trading arrangements across simple hybrid offshore structures (namely offshore renewable generation linked to interconnectors) in the context of the European Electricity Target Model
- Assess the impact of national renewable energy support schemes on trading across and investment in hybrid offshore infrastructure, taking account of the Commission guidance on renewable support schemes
- Consider the possible use of long term transmission rights by offshore renewable generators, the need for priority dispatch by offshore renewable generators and the impact of zero or negative prices on hybrid offshore infrastructure
- Produce proposals for allocating the costs of hybrid offshore structures, liaising with ACER to ensure compatibility with their work on cross-border cost allocation (CBAC)
- Consider options for anticipatory grid investment
- Consider the impact of asset classification on trading across and investment in hybrid offshore infrastructure

1.3 Aims and objectives of this paper

In order to address the first deliverable for 2014 set out above, this paper develops our thinking on market arrangements to facilitate trading from across simple hybrid offshore structures (namely offshore renewable generation linked to interconnectors) in the context of the European Electricity Target Model.

We expand on the issues discussed in the NSCOGI discussion paper *Possible Market Arrangements for Integrated Offshore Networks* ("The NSCOGI Possible Market Arrangements Paper") and consider how offshore renewable generation (ORG) would operate under the different timeframes of the Electricity Target Model.[1] In addition to considering further the day ahead timeframe, we set out our thoughts on how an ORG might operate over the forward and intraday timeframes.

2. Background - The NSCOGI Market Arrangements Paper

This section recaps on the model for analysis, key assumptions and preliminary conclusions of the NSCOGI Possible Market Arrangements Paper[2]. This paper uses the same basic model and assumptions as the Possible Market Arrangements Paper to explore further trading scenarios under the Electricity Target Model.

2.1 Market arrangements Paper – Model for Analysis

The Possible Market Arrangements Paper set out a basic physical model for analysing how ORG would operate under market coupling: a hybrid interconnector asset linking two bidding zones in two different Member States A and B and an offshore renewable generator (ORG). This hybrid interconnector is used both for transporting cross-border flows (as with a conventional interconnector between two bidding zones) and production from offshore renewable generation. It focused only on the day ahead timeframe.

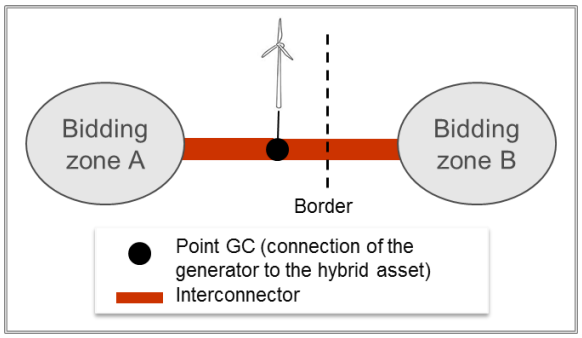

Figure 2 – Basic Model of hybrid asset

[1] See http://www.benelux.int/NSCOGI/NSCOGI_Discussion_Paper_Possible_Market_Arrangements_Integrated_Offshore_Networks.pdf
[2] Ibid.

In considering the interactions between cross border trading and production of the renewable generation from the ORG in this basic model, we identified two key principles that the analysis must respect:

- **Priority Access** and Priority Dispatch **for Renewable Energy Sources** as per the Renewables Energy Directive.[3]
- **Congestion Management Guidelines (CMG) and EU Target Model** as per the Third Energy Package legislation (in particular Regulation 714/2009, Framework Guidelines and Network Codes). The underlying principle of the CMG and Target Model is that electricity should flow between price or bidding zones according to price differentials.

The first principle gives priority access and priority dispatch for renewable energy sources. The second establishes that electricity should flow according to price differentials through the use of market based implicit energy and capacity auctions, and that cross-border flows should not be reduced to solve a country's internal congestion. In the case of a hybrid asset, used both for transporting offshore renewable generation and cross-border trade, it is important to clarify who has priority access when congestions occur (i.e. when demand for flows exceed the transfer capacity of the hybrid asset).

The paper also set out other important criteria for analysis:

- **Compatibility with current national legal frameworks** (as far as applicable frameworks exist)
- **Maximisation of social welfare** – generation costs, costs and benefits paid and received by grid users including resulting market price
- **Consistency of the regulatory framework** (**e.g. non-discrimination**), i.e. an ORG connected to a hybrid structure should be treated the same way as any other ORG
- **Incentive value** – is the proposed arrangement acceptable for the ORG? For the IC operator? The most efficient behaviour should be incentivised (i.e. combined assets being preferred to radial connections plus IC when this is more efficient from a macro-economic view).

2.2 Market Arrangements Paper - Virtual Case Studies

The Possible Market Arrangements Paper set out a number of "Virtual Case Studies" to consider how an ORG might operate, respecting the principles set out above. Two Virtual Case studies (VC) were considered:

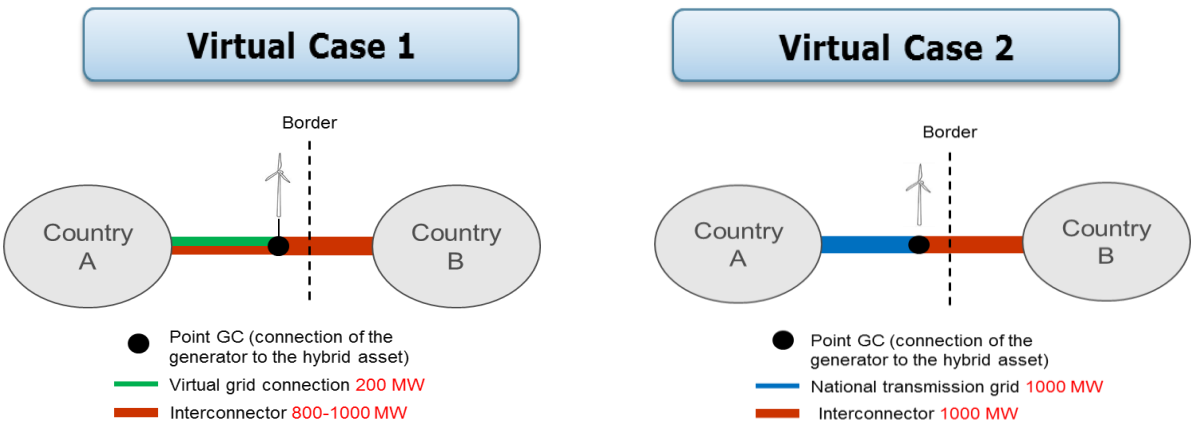

Figure 3 – Virtual Case Studies 1 and 2

[3] Directive 2009/28/EC

Virtual Case Study 1 (VC1)

There are two bidding zones, A and B, in two different countries. The two bidding zones are joined by an interconnector (IC) with a capacity of 1000MW. An ORG (capacity 200MW) is attached to this asset. The entire connection between the ORG and bidding zone B is defined as an IC. The 200 MW portion of the IC between the ORG and bidding zone A is classified partly as a "virtual" grid connection, partly as an IC (cf. Figure 1). The capacity of the "virtual" grid connection equals the foreseen actual generation of the ORG at each hour.

Virtual Case Study 2 (VC2)

VC2 is a variation from the VC1 model. There are two key changes to note: firstly, the link from the country of bidding zone A to the ORG is defined as a part of the national transmission system, while the link between the ORG and country of bidding zone B is classified as an IC – hence there is no hybrid status of assets.

Options for Study:

Building on these two virtual case studies, four different bidding zone configurations were considered to explore the optimal market arrangements for an ORG. These were:

- **Option 1**: ORG in fixed bidding zone under virtual case 1 (VC1).
  In this option, the ORG is domiciled in bidding zone A through a "virtual" grid connection. The ORG is treated as any other trader in bidding zone A.
- **Option 2:** ORG in a floating bidding zone.
  In this option, the ORG is able to 'float' between bidding zone A and bidding zone B depending on its expectation of the prices in each bidding zone.
- **Option 3:** ORG in its own bidding zone.
  In this option, the ORG is placed in its own bidding zone separate to both bidding zone A and bidding zone B.
- **Option 4:** ORG in fixed bidding zone under virtual case 2 (VC2).
  This options is very similar to Option 1: the ORG bids into bidding zone A as any other market participant in bidding zone A, except that in this case the link between the ORG and bidding zone a is deemed to be part of the national transmission grid in the country of bidding zone A.

In both options 1 and 4, the ORG bids in a fixed bidding zone (its national bidding zone): they have the same effect on the market, and in case of congestion, may apply the same solutions. They only differ in their asset classification.

2.3 Market arrangements Paper - Congestion Management

All the options discussed in the Possible Market Arrangements Paper proved to optimise flows, and thus minimise market prices, provided that the right congestion solution is applied. Following analysis of the four options under the assessment criteria, NSCOGI concluded that Options 1 and 4 (ORG always bidding into a fixed bidding zone) seemed to represent the best solution. We describe how congestion management would work for Option 1 below:

Day Ahead Market Coupling Option 1 – National Bidding Zone

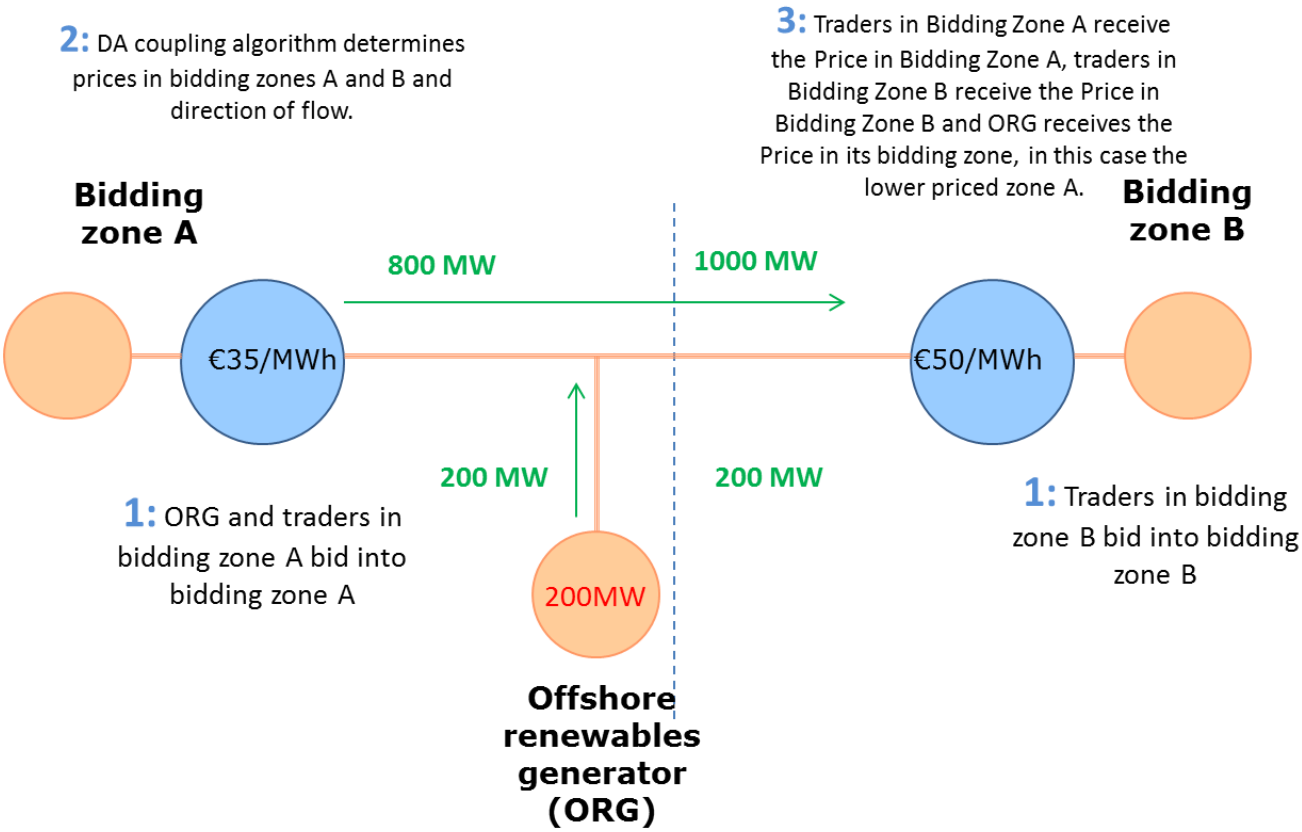

Figure 4: ORG operating in National Hub A

In the diagram above the ORG is accepted into the merit order in bidding zone A on the basis that it will bid in a zero price (given zero or low marginal costs). Where the prevailing flow is from A to B and if the ORG is producing to full capacity, the ORG will supply 200 MW to bidding zone A, with 1000 MW exported from bidding zone A to bidding zone B.

However, issues may arise when the prevailing flow is from bidding zone B to bidding zone A. In this case, there is a conflict between cross-border flows and transmission of the ORG production to bidding zone A, both needing access to a (hybrid) congested asset.

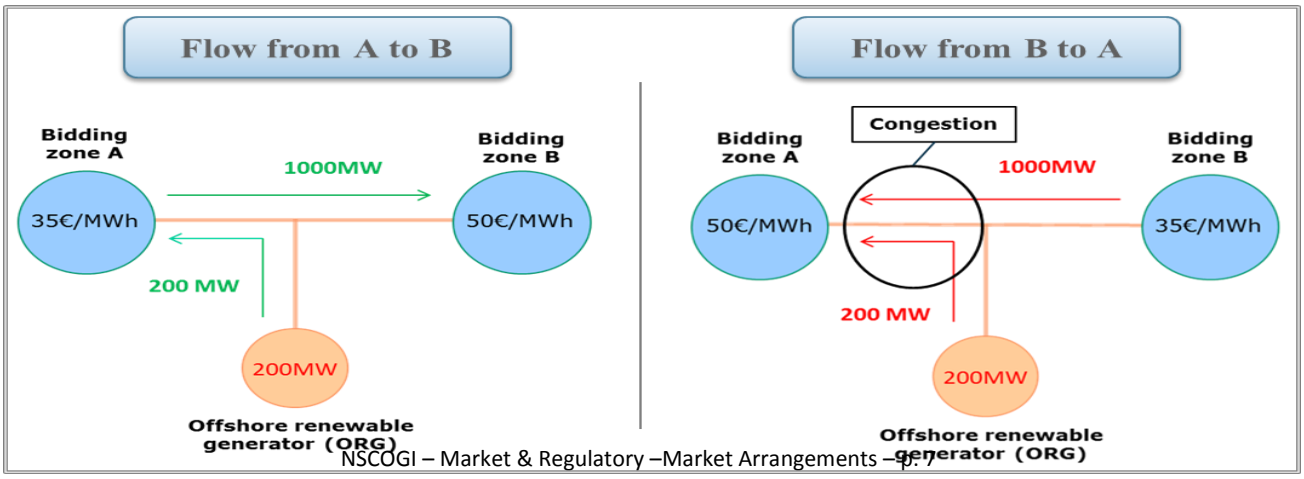

Figure 5 - Congestion management

To resolve this conflict, NSCOGI concluded that it would be preferable to give priority to the ORG over cross-border flows, even when this leads to reductions in day-ahead interconnection capacities.

2.4 Market Arrangements Paper: Conclusions

The initial analyses in the Possible Market Arrangements Paper led to the following conclusions, to be taken forward for further analysis in subsequent studies:

1. Even if it is connected to several bidding zones in different countries (for example by being connected to an interconnector (IC)), an Offshore Renewable Generator (ORG) should only be allowed to bid into one bidding zone.
2. In case of a conflict between ORG generation and cross-border trade on the same congested assets, the ORG should be "prioritised" in a manner consistent with the national approach taken onshore or for other RES connected to the national system, even when this leads to reductions in day ahead interconnection capacities.
3. The ORG should be charged for the asset connection in the same way as radially connected ORG (e.g., in most NSCOGI countries this charge is based on the transmission asset costs). Under the current frameworks, this implies that the ORG would not need to buy capacity on the interconnector to get access to the bidding zone into which it bids.
4. Additional analysis may also be warranted to explore the use of long term capacity rights in specific cases, in particular for consideration as a possible mechanism to facilitate renewables trading between Member States.

In the earlier paper, only the day-ahead timeframe was considered. The paper's conclusions are subject to a number of assumptions, in particular that interconnection capacity is allocated through implicit auctions via a single price coupling algorithm, as foreseen in the Framework Guidelines on Capacity Allocation and Congestion Management (FG CACM). Criteria such as social welfare, stability of and compatibility with legal frameworks and incentive value were taken into account in the analysis in general qualitative terms.

3. Developments in Thinking - ORG and the Electricity Target Model

3.1 Developments in Thinking since the Possible Market Arrangements Paper

Since the publication of the Possible Market Arrangements Paper, NSCOGI Working Group 2 has engaged with stakeholders on the initial analysis set out in that paper and developed its thinking on how ORG would operate under other key timeframes for electricity trading (notably intra-day and forward). Three stakeholder workshops were held (in April, June and October 2013) and constructive engagement was carried out with a wide range of stakeholders including the European Commission, Eurelectric, the European Wind Energy Association, EFET and Europex. This paper attempts to update our analysis based on those stakeholder interactions and to present further considerations to stakeholders to elicit debate and provide evidence to policy makers on the key interactions between the internal electricity market and an integrated offshore grid.

The Possible Market Arrangements Paper focused on the Day Ahead timeframe assumed that all electricity is traded day ahead through an implicit auction as part of the pan European day ahead market coupling. Given the importance of within day fluctuations in wind forecasts, demand and plant outages and the requirement in the Electricity Balancing Network Code that all market participants are balance responsible, the intra-day timeframe is becoming an increasingly important element of the European Target Model. It is therefore instructive to consider how an ORG would operate and how congestion management would work at the intra-day as well as the day ahead timeframe. Capacity allocation across timeframes and financial hedging including energy options that reveal the value of flexibility are further factors that determine how ORGs might participate in the various markets[4].

Similarly, the forward timeframe (that is forward capacity allocation and cross border hedging) is a potentially important timeframe for considering how an ORG can access cross border capacity[5] Any advantages of allocating transmission rights for an ORG linked to a hybrid asset need to be carefully balanced against concerns that the ORG would be exposed to a market risk to which radially connected ORGs are not exposed to the same degree, as only an ORG connected to hybrid infrastructure assets would depend entirely on access to cross border capacity to sell its generation. The nature of the transmission right and the competitiveness of the explicit capacity auction are further considerations that need to be taken into account if this option is studied further.

Finally, bidding zone configuration is a key feature of the Target Model. The Target Model envisages a zonal market design which addresses network congestions between bidding zones. The options set out in the Possible Market Arrangements Paper essentially consisted of different bidding zone configurations for ORGs connected to hybrid assets. However, the draft CACM NC requires periodic assessment of the efficiency of bidding zone configuration and potential review of current and alternative configurations. ACER and ENTSO-E are currently undertaking an assessment and review of the bidding zone configuration in some parts of Europe as part of early implementation of the CACM NC.[6] It is clear that bidding zone configurations have an

[4] For more on energy options see this recent consultancy study on valuing flexibility : http://www.poyry.com/sites/default/files/imce/files/revealing_the_value_of_flexibility_public_report_v1_0.pdf

[5] For more on long term transmission rights and the target model see: http://ec.europa.eu/energy/gas_electricity/studies/doc/electricity/2012_transmission.pdf

[6] See: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Report%20on%20Bidding%20Zones%202014.pdf

important effect on the market and may evolve over time. This will impact on bidding zone configurations for offshore meshed grids.

3.2 The Target Model – efficient capacity allocation and trading across timeframes

As stated above, the European Target Model is about more than day ahead market coupling. It is also concerned with efficiently allocating scarce cross border capacity and managing congestion across different timeframes (ref. Regulation714/2009) to create an efficient and holistic market design for the European internal electricity market.

The detailed market rules of the Target Model are being drawn up by ENTSO-E and passed to ACER and the European Commission in the form of three European Network Codes – the CACM NC, the Network Code on Electricity Balancing and the Network Code on Forward Capacity Allocation - which will then be approved by Member States and the European Parliament to become binding regulations. The diagram below illustrates the key features of the network codes

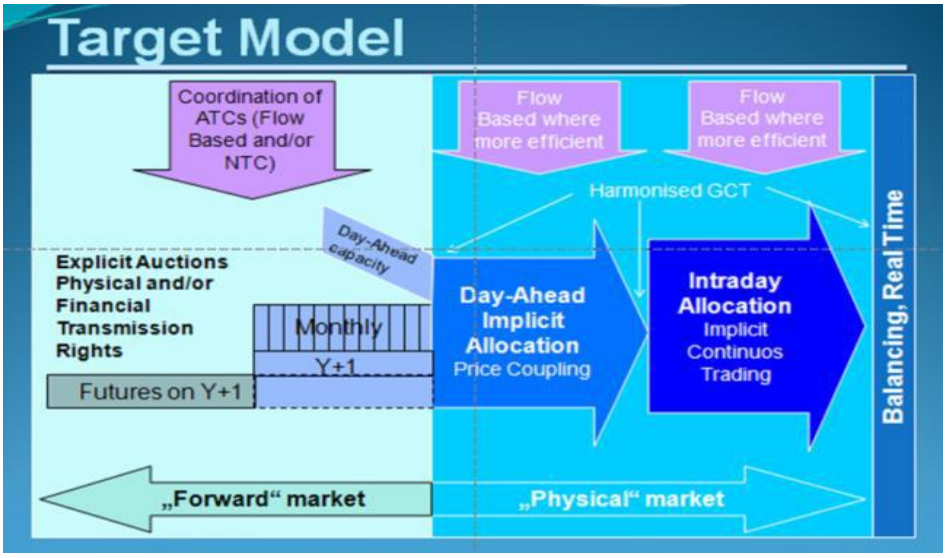

Figure 6: The Electricity Target Model. Source: ENTSO-E

Upon entry into force, these Network Codes will apply to all cross border trade in electricity in the European Union, including meshed systems of ORGs trading across zones and Member State borders. As such it is useful to set out the key high level requirements of the Target Model as set out in the relevant Framework Guidelines and Network Codes that will apply to ORGs.

Capacity Calculation

- The draft CACM Network Code requires the use of either a Flow-Based (FB) method or a Coordinated Net Transmission Capacity (NTC) method for capacity calculation at each zone border for a given timeframe. Both methods shall make use of locational information on relevant generation and consumption units, through a detailed common grid model and ensure compliance with legal provisions for transparency.

Definition of Zones for Capacity Allocation and Congestion Management

- The draft CACM Network Code defines a zone as a bidding area, i.e. a network area within which market participants submit their energy bids day-ahead, in intraday and in the longer term timeframe.

- The draft CACM Network Code requires periodic assessment of the bidding zone configuration and a number of possible reasons to launch a review of zone configuration, including any inefficiencies identified in the periodic assessment.

Day Ahead Market Coupling

- The draft CACM Network Code requires capacity allocation in the day ahead market to be on the basis of implicit auctions via a single price coupling algorithm which simultaneously determines volumes and prices in all relevant zones, based on the marginal pricing principle.

- If there is insufficient transmission capacity to enable all requested trades, the zonal prices calculated will differ. The single price coupling algorithm calculates volumes and prices for all bidding areas and for each time unit.

Intra Day Market Coupling

- The CACM FG set out the key feature of the intraday market as being to enable market participants to trade energy as close to real-time as possible in order to (re-)balance their position. The draft CACM Network Code provides for the implementation of intra-day market coupling supporting continuous implicit trading, with reliable pricing of intraday transmission capacity reflecting congestion (i.e. in case of scarce capacity).

- The Network Code also provides that where there is sufficient liquidity, regional auctions may complement the implicit continuous allocation mechanism. Where implemented, implicit auctions should have adequate bidding deadlines to provide the necessary flexibility to the market and be coordinated with, and linked to, the pan-European target model.

- As a transitional measure, the Network Code also allows for direct explicit access to the capacity.

Forward Capacity Allocation

- The CACM FG describe the objective of long-term transmission rights, physical or financial, as being to provide market participants with long-term hedging solutions against congestion costs and the day-ahead congestion pricing, compatible with zone delimitation.

- The draft Forward Capacity Allocation Network Code provides that options for enabling risk hedging for cross border trading are Financial Transmission Rights (FTR) or Physical Transmission Rights (PTR) with Use-It-Or-Sell-It (UIOSI), unless appropriate cross-border financial hedging is offered in liquid financial markets on both sides of an interconnector.

Electricity Balancing

- The Framework Guidelines on Electricity Balancing cover the rules for trading related to technical and operational provision of system balancing and the balancing rules including network-related power reserve rules that strive for integration, coordination and harmonisation of the balancing regimes. The Target Model for balancing focuses on exchanges of balancing energy which are to be based on a TSO-TSO model with a common merit order list.

- The current Balancing Network Code establishes common rules for Electricity Balancing including the establishment of common principles for procurement and settlement of Frequency Containment Reserves, Frequency Restoration Reserves and Replacement Reserves and a common methodology for the activation of Frequency Restoration Reserves and Replacement Reserves

Figure 7: Offshore Renewable Generation (ORG) connected to a hybrid asset operating under the Target Model

3.3 Assumptions for ORGs connecting to a Hybrid Model under the Target Model

As with the first market arrangements paper, in this paper we assume that the assets are subject to the requirements of the Target Model across all timeframes and that the ORG is sensitive to the market price in each market that it trades in. We also assume that capacity is allocated according to the NTC Methodology and that bidding zones are defined based on the principles of overall efficiency, as envisaged in the CACM Network Code.

Further, we assume that interconnection capacity rights (physical or financial) are allocated at the forward timeframe (if any) through explicit auctions, at the day ahead stage through implicit auctions via a single price coupling algorithm and through the shared order book (SOB) at the intra-day timeframe. We do not consider how cross border balancing might affect an ORG in this paper.

Another assumption through the paper is that the marginal cost of the ORG is lower than the market price in both markets A and B, on the plausible grounds that its opportunity costs are close to zero (or even negative). If one of the markets had an oversupply of variable energy (i.e. extremely low or negative prices), our conclusions would need more analysis.

4. ORG in Day Ahead Market Coupling

The Possible Market Arrangements Paper concluded that:

- An ORG connected to several bidding zones should only be allowed to bid into one of them.
- In the case of congestion between ORG generation and cross-border trade on the same assets, the ORG generation should be "prioritised" in a manner consistent with the national approach taken onshore or for other RES connected to the national system, even when this leads to decreased day ahead interconnection capacities.
- The ORG should be charged for the asset connection in the same way as a radially connected ORG (e.g., in most NSCOGI countries: based on the asset costs). Under the current frameworks, this implies that it would not need to buy interconnection capacities to get access to the bidding zone into which it bids.

4.1 Stakeholders Views

Since publication of the first Market Arrangements Paper, stakeholders have given further consideration to the merits of these various issues[7].

Bidding Zones

Stakeholders were of the view that market coupling as it is designed today, helps to schedule offshore renewable generation: the currently developing day ahead and intraday markets are conceived to deliver the lowest cost generation schedule. If the offshore renewable generation bids into the day ahead market at close to zero price, it will be scheduled in the market coupling algorithm. The main issue is what price this offshore renewable generation receives. This is a political and regulatory issue, according to Europex.

Several stakeholders (EWEA, Eurelectric and EUROPEX) have suggested NSCOGI reconsider some options which were discarded. Europex, in particular, consider that Option 3 (where the ORG is classified as being in its own, separate bidding zone) a useful option to pursue for the day ahead timeframe. This is because, although the ORG always receives the lowest price under Option 3, no conflict between cross border flows and ORG production occurs (and therefore congestion rent is not affected). In this case, the congestion problem is solved through market coupling.

According to EUROPEX, the possible loss of congestion rents is an important issue to take into account. In general, there will always be a financial transfer in the options studied: a transfer from the interconnector operator to the ORG, or a transfer from the RES support scheme to the ORG, or from the support scheme to the interconnector operator. There will always be an effect on the congestion rent and this will be more or less important, depending on which regime is applied and on how the value of the capacity is considered. In order to ensure that the ORG finally receives the price in bidding zone A, transfers from the TSO to the ORG can be considered.

However, EWEA agreed with the conclusions of the Possible Market Arrangements Paper and considered that Option 1 and 4 (the ORG in a national bidding zone) as the optimal ones. Options 2 and 3 should be

[7] Stakeholder views were elicited at two NSCOGI focus groups in April and June 2013 as well as through informal correspondence.

discarded as not practically applicable. EWEA argued that Option 3 would not be an economically sustainable solution for the ORG in the day-ahead timeframe as it would always receive the lowest price[8]. EWEA also agreed with NSCOGI that an ORG connected to several bidding zones should only be allowed to bid into one of them at a time.

Several stakeholders have argued, as a general point, that bidding zones should be consistent across all timeframes in order to avoid perverse outcomes/gaming.

Some stakeholders took the view that market coupling can be adapted to deal with all the options in the paper. Others took the view that bidding zone configurations could change over time with a potential model being that ORGs are domiciled in national bidding zones (Options 1 or 4) initially and over time. However, as an integrated meshed grid develops, several ORGs could form their own offshore bidding zone (Option 3).

Priority Dispatch

EWEA considers that when referring to priority dispatch, a distinction should be made between trading and operational priority dispatch. When it comes to trading, the rationality of the market coupling algorithm will schedule the generator with the lowest marginal cost and so lower marginal cost renewable generators will not need priority dispatch. But, once the day ahead weather forecast is calculated, a wind producer no longer has the opportunity to adapt its schedule for the purposes of market coupling. Moreover, due to its low marginal price, the wind generator is easily reduced in case of re-dispatching.

Some stakeholders (EUROPEX, Eurelectric), were of the view that RES should be sensitive to market prices and support schemes should not result in market distortions. The 'minimum market price' should relate to real costs, otherwise the market is meaningless. Europex noted that ultimately it is about welfare optimisation and an efficient economy, so bids and offers should reflect real costs.

Since the offshore grid infrastructure considered may not be realised before 2020, EFET questioned whether the current priority dispatch provisions under the Renewables Directive and the current Congestion Management Guidelines needed to be kept as key assumptions for the market arrangements work.

Congestion Charging

With regard to congestion charging, EWEA considered the following two options as feasible for an ORG:

1. ORG gets priority access "for free", i.e. the costs being socialised through the transmission tariff or:

2. ORG pays for the priority access to the interconnector, reimbursing the system operator costs paid for reserved/used capacity

EWEA consider that the choice between these two options should be determined on a case-by-case basis, taking into account the access compensation scheme applied to radially connected ORGs in the two respective countries where the integrated offshore grid solution is located. In order to give an appropriate incentive to the ORG to connect to an integrated offshore grid, the respective ORG should be charged for the asset connection in at least the same way as a radially connected ORG, if not in a more advantageous way.

[8] EWEA take a different view on the own bidding zone option for intraday, as shall be explained in section 2.

4.2 NSCOGI Response

Bidding Zones

We agree with stakeholders that the key consideration here is the market price that the ORG receives under the different options, and not the zone it bids into. With an appropriate compensation mechanism for the ORG, Option 3 could possibly be envisaged. We therefore consider that Option 3 is worth further analysis at the day ahead stage, in particular in terms of how it interacts with congestion revenues and support mechanisms.

We agree that changes to bidding zones across timeframes could have unintended consequences, so for this reason Option 3 is kept as a distinct option for all timeframes - day ahead, intra-day, forward. We will explore Option 3 further in Section 2, in considering how an ORG would trade in the intra-day market.

We also agree that bidding zone configurations for ORGs could evolve over time and that a potential solution could be to begin with Option 1 or 4 and progress to Option 3 for a cluster of ORGs as the meshed offshore grid develops.

As for the consequences of Option 4 (i.e. that only 800 MW would be available for market coupling), we consider that capacities that are not needed for forecasted renewable generation (ORG) should be allocated through market coupling – thus the capacity results would be the same as for the other options.

We conclude that the following options are feasible for ORG and should be used as models for further analysis of market arrangements:

- Options 1 and 4: ORG in a national bidding zone.
- Option 3: ORG in its own bidding zone.

As the market arrangements are broadly equivalent for Options 1 and 4, this paper focuses on Options 1 and Option 3 for the intraday timeframe[9].

Priority Dispatch

Regarding Priority Dispatch and negative prices, throughout the market arrangements work we have assumed that the short run marginal cost of the ORG is lower than the market price in both markets A and B, which is plausible given that the avoidable costs of an increment in wind generation are close to zero. If one of the markets has an oversupply of zero marginal cost energy (i.e. extremely low or negative prices[10]), the conclusions reached would need more analysis. This is an area of future study for NSCOGI.

[9] The NSCOGI paper on Cost Allocation deals with Options 1 and 4 as these are more relevant for this piece of work.

[10] For more on implications of negative prices see: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48373/5358-annex-b-feedin-tariff-with-contracts-for-differe.pdf

Congestion Charging

Consistent with the conclusion reached in the Possible Market Arrangements Paper, the preferred option is that the ORG should be charged for the asset connection in the same way as a radially connected ORG. This could mean either that it pays for priority access to the cross border capacity or that it is awarded such access and costs are socialised through tariffs.

Under the current frameworks, this implies that it would not need to buy interconnection capacities to get access to its national bidding zone. However, while this should not be a requirement we consider that it should not be precluded as an option if agreed by the concerned ORGs, TSOs and NRAs.

The Forward Capacity Allocation Network Code, as currently drafted, allows for physical and financial transmission rights to be allocated for cross zonal capacity. In the general case transmission rights could be sold, as for any interconnector, for the capacity of the hybrid asset between the local bidding zone (Bidding Zone A in Option 1) or the own bidding zone of the ORG (Bidding Zone C in Option 3) and the other Bidding Zone (Bidding Zone B in both options). The issue for consideration is if, under Option 3, multiannual financial transmission rights were to be auctioned or allocated for a hybrid asset in its own bidding zone (Bidding Zone C), this could be one means of an ORG securing direct access to its national network, i.e. bidding zone A. It would be important, however, not to unduly discriminate between market participants in any use of transmission rights for ORGs. How either of these two regimes might operate with an ORG connecting to a hybrid interconnector is considered further in section 6.

5. ORG in Intra Day Market Coupling

5.1 Assumptions

In this section, we develop Options 1 and 3 for the Intra Day timeframe. It is important to note that the analysis of the intraday timeframe set out below must respect the principles of:

- **Priority Access and Priority Dispatch** for generation from renewable energy sources (RES) as per the Renewables Directive[11].
- **The EU Target Model** – the key issue being that electricity should flow according to price differentials between bidding zones. In this paper we focus on the intraday timeframe, for which continuous implicit trading via a single matching algorithm (complemented by implicit auctions and allowing for explicit

[11] The Renewables Directive says that *priority access implies that assurance is given to connected generators of electricity from renewable energy sources that they will be able to sell and transmit the electricity from renewable energy sources in accordance with connection rules at all times, whenever the source becomes available.* It gives MS the alternative to provide either guaranteed or priority access.

Priority access is considered to be (implicitly) given in support systems including a purchase obligation (FIT systems), while guaranteed access is considered to correspond to a situation where the RES electricity is sold on the market: In the event that the electricity from renewable energy sources is integrated into the spot market, guaranteed access ensures that all electricity sold and supported obtains access to the grid, allowing the use of a maximum amount of renewable energy sources from installations connected to the grid. For the sake of convenience the term priority access is used here to refer to both situations.

Priority Dispatch refers to the obligation on transmission system operators to give priority of dispatch to renewable generators insofar as secure operation of the national electricity system permits as set out in Article 16(2)(C) of the RES Directive.

access to intra-day capacity as a transitional measure) is the Target Model, as defined in the CACM FG and draft CACM Network Code.

Moreover, as for the day ahead timeframe, other important criteria for analysis are:

- **Compatibility with current national legal frameworks** (as far as applicable frameworks exist)
- **Maximisation of social welfare,** which is defined as the sum of the producer and consumer surpluses across the region under study, plus any congestion rent accruing to TSOs from the use of the interconnectors
- **Consistency of the regulatory framework (**e.g**.** non-discrimination), i.e. an ORG connected to a hybrid structure is treated the same way as any other ORG
- **Incentive compatibility** – is the proposed arrangement acceptable to the ORG? To the IC operator? The arrangements should incentivise the most efficient behaviour on the part of those affected (e.g., combined assets being preferred to radial connections plus IC when this is more efficient from a macro-economic view).
- As with the Possible Market Arrangements Paper, in this paper we assume that the ORG is sensitive to the market price, i.e. that it is integrated into the spot market. Although this is not currently the case in all NSCOGI countries, it will be the case when offshore renewables become competitive and support schemes are no longer needed. Moreover, some support schemes make the ORG price sensitive[12].

Another assumption throughout the paper is that the short run marginal cost of the ORG is lower than the market price in both markets A and B, which is plausible given that the avoidable costs of an increment in wind generation are close to zero. As stated above regarding priority dispatch, if one of the markets has an oversupply of zero marginal cost energy (i.e. extremely low or negative prices), the conclusions reached here would need more analysis.

5.2 The Virtual Case Study for intra day

As stated above, the Possible Market Arrangements Paper put forward two virtual case studies for assessing the operation of ORGs in the single electricity market. In this section on the intraday market we focus on virtual case study 1, which is illustrated for information below[13].

[12] The impact of the different support schemes applied to renewables will be discussed in further work.
[13] Option 4, which is based on Virtual Case Study 2, leads to largely similar outcomes as Option 1 in the Possible Market Arrangements Paper

Figure 1: **Virtual Case Study 1**

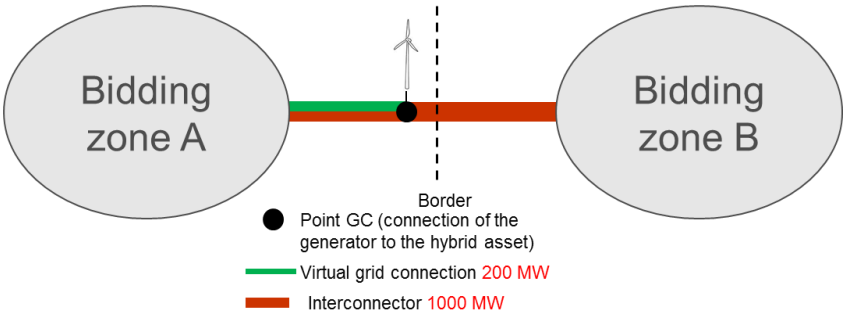

Figure 8: Virtual Case Study for intra-day timeframe

5.3 The Intraday Target Model

The target model for the intraday timeframe is set out in the CACM Framework Guidelines and draft CACM Network Code. Capacity is allocated through continuous implicit trading, with a pricing mechanism for capacity to be developed in the event of congestion. The intra-day target model also allows for the implementation of regional implicit auctions subject to specific criteria including liquidity requirements[14]. The intra-day target model also allows for direct explicit access for Intra-day capacity via the capacity management module on a transitional basis subject to certain criteria. The intraday timeframe runs from after the day ahead timeframe until immediately prior to the balancing timeframe (i.e., gate closure an hour ahead of real time).

Figure 2 below sets out the key aspects of the intraday timeframe.

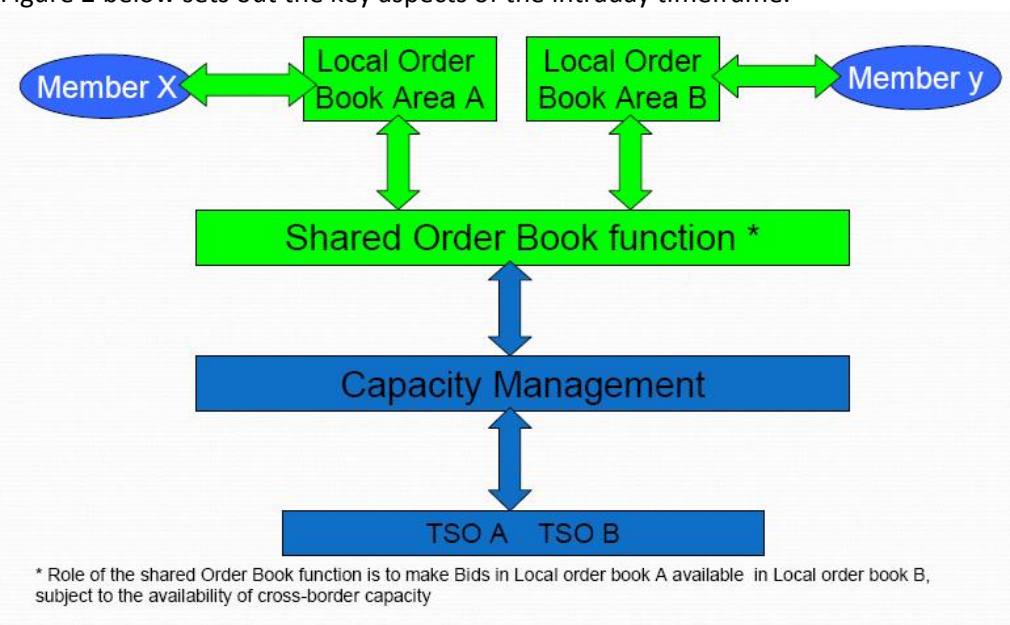

Figure 9: Intra Day Target Model. Source: ENTSO-E

[14] Intraday implicit auctions may also be developed as an efficient means of pricing intraday capacity

It is likely that the intraday timeframe may be as important for generation with more variable output such as ORGs than the day ahead timeframe. For example, at the day ahead stage the ORG may not be able to predict output with sufficient accuracy and therefore the intra-day market should facilitate adjustments from the day ahead schedule arising from forecast errors. As a result, ORGs would need to utilise the intraday market to trade out the differences between what they committed to at the day ahead stage and actual output.

5.4 Intra Day Congestion Management and Zone Delineation

Given the analysis that has already been carried out for the day ahead time frame in the NSCOGI Market Arrangements Paper, it makes sense to assess the intraday timeframe using the same options. However, in this example it is assumed that at the day ahead stage the interconnector is fully committed in the direction from A to B and the ORG had committed to 150 MWh of generation in the hour under study. Social welfare is maximised by the flow of 1,000MW into bidding zone B. Because the IC is congested, prices in bidding zones A and B are not equalised; and the TSO accrues a congestion rent of €15,000 in the hour. This is set out in Figure 3 below.

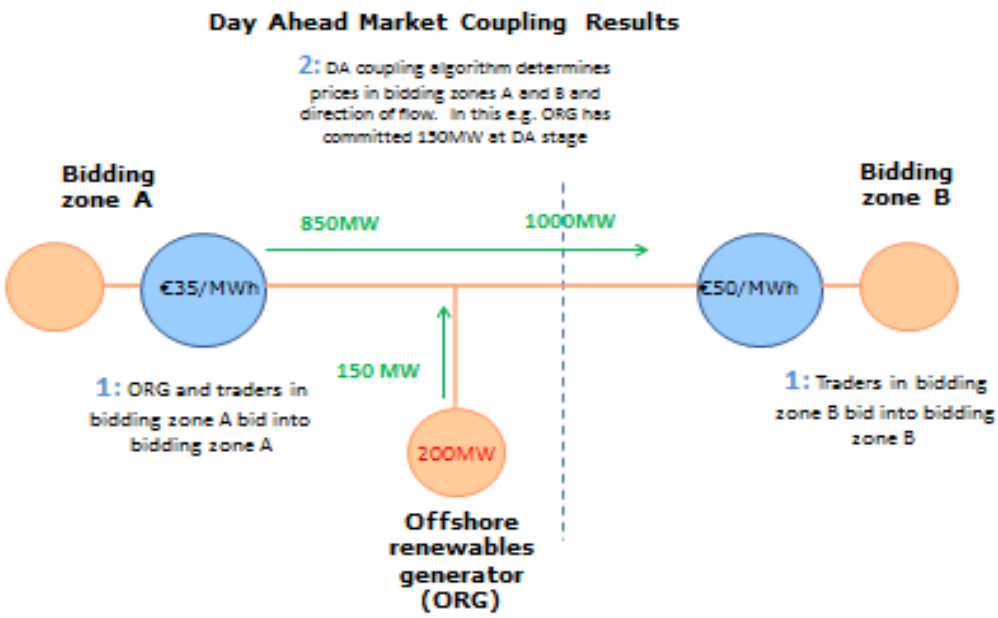

Figure 10: Day Ahead market coupling results

Note: The green arrows indicate the direction of the commercial flows rather than the physical flows. The physical flow is 850 MW out from A and 1000 MW into B.

For the purposes of the analysis below it is assumed that in the intra-day timeframe the ORG has an additional 50MWh of output to trade above and beyond what it has committed in the day ahead timeframe; and that everything else (e.g. load, non-ORG generation) is equal. In the next section we consider how this

conflict between cross-border flows and transmission of the ORG production to bidding zone A is managed in the intra-day timeframe.

5.5 Intra Day Options

Option 1: ORG in national bidding zone

In this example, the ORG is domiciled in bidding zone A. The ORG is treated on the same basis as any other trader in bidding zone A. The trading mechanism can be described as follows:

- Traders in bidding zone A and the ORG bid into bidding zone A; traders in bidding zone B bid into bidding zone B
- Bids and offers from bidding zone A (including those of the ORG) and bidding zone B are submitted by local market operators to the Shared Order Book. The continuous trading matching algorithm matches bids and offers on a first come first served basis, always assuming that there remains sufficient available capacity on the interconnector between bidding zone A and bidding zone B.
- In the example in Figure 3 above, the additional 50MWh from the OWG can only flow within bidding zone A. This is because the capacity on the interconnector between bidding zones A and B is already fully utilised.[15]
- In theory, if there is no bid in bidding zone A to match the offer from the ORG then its additional output cannot be sold and the ORG would have to be constrained off/curtailed.

If the ORG's offer of 50MWh is matched by a bid in bidding zone A, then 50MWh of energy will flow from the ORG to displace more expensive generation in bidding zone A (assuming load is unchanged). Where the additional 50MWh from the ORG is accommodated there would appear to be no issue. In this case:

- **Priority access**: RES will be dispatched and the outcome is consistent with the objectives of priority access.
- **CACM Network Code:** Intraday physical flows are accommodated by the matching algorithm, with the result that less expensive generation in bidding zone A displaces more expensive generation in bidding zone A and social welfare increases.
- **Non-discriminatory** – ORG is treated like any other generator (ORG or not) which would have to be domiciled in a particular bidding zone

[15] The price in bidding zone B (€50/MWh) exceeds that in bidding zone A (€35/MWh), This means that the interconnector in the direction bidding zone A to bidding zone B is congested. If there was spare capacity on the interconnector, prices in the two bidding zones could not be different.

ORG in National Hub

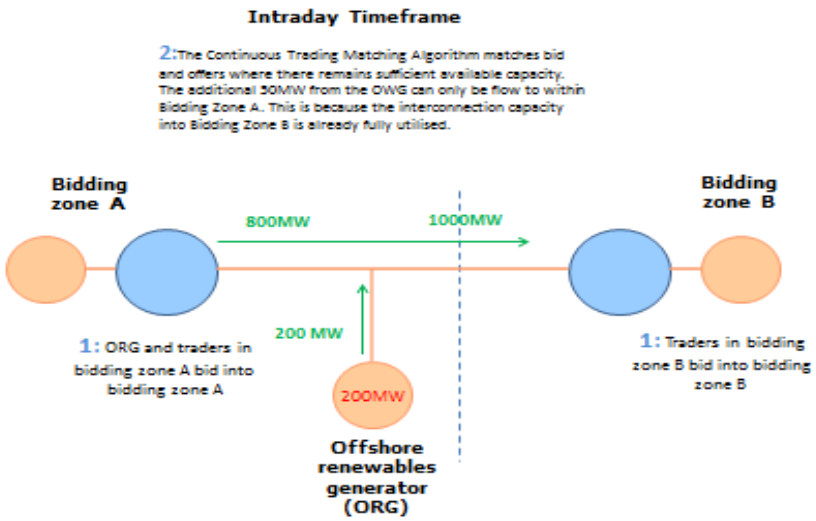

Figure 11: Day Ahead market coupling results

However, issues may arise if the interconnector is congested in direction B to A. The ORG's offer of 50MWh could still be matched by the Shared Order Book with a bid in bidding zone B rather than zone A. But the ORG would no longer have access to offers in Bidding Zone A and therefore this Option may no longer be, strictly speaking, considered Option 1 at the intraday stage. In this case there is a conflict between cross-border flows and the transmission of the ORG to bidding zone A or bidding zone B, both needing access to a congested asset. There are a number of routes available:

a) ORG is constrained off the system and compensated accordingly or;

b) ORG, in the direction B to A, pays for firm access to the IC (capacity commensurate with full potential output of the ORG is reserved through the forwards, day ahead and intraday timeframes). However, this may raise an issue with compatibility with the Target Model or;

c) Priority dispatch with reservation of variable capacity on the IC. The ORG is not charged for the use of the asset in any way – except use of system charges.

As with the day ahead timeframe explored in the Possible Market Arrangements Paper, if route **(a)** is pursued**,** overall generation costs may be higher than they would otherwise have been if the additional (low short run marginal cost) output from the ORG had been accommodated. Specifically, constraining ORG in order to maintain maximum IC capacity would result in more expensive generation in bidding zone A being kept on the bars when it could have been offset by additional low marginal cost generation from the ORG.

If we now consider the alternative of route **(b)** whereby the ORG pays for firm access to the IC (guaranteed up to the end of the intraday timeframe), the question becomes how the charge is calculated. In the forwards timeframe IC capacity would be reduced by the full capacity of the ORG (200MW). At the day ahead stage, IC available capacity would be reduced based on the day-ahead wind power forecast (with a

potential inclusion of a forecasting error factor). Capacity not utilised in the day ahead timeframe would be available on a first come first served basis in the intraday continuous trading.

So as not to be considered discriminatory as against other IC users, one might argue that the IC capacity would have to be made available to all users. However, with the ORG being the only generator to depend entirely on the use of the IC to transport its generation to the market, the situation could be sufficiently different from other generators to justify a different, non-discriminatory treatment. Also, in this scenario the ORG would be paying for this firmness.

Finally with respect to priority access, the RES generation will be given priority dispatch over any other generation and is guaranteed firm access rights to the system. By comparison with (b), it does not pay for these access rights, as they are guaranteed as part of the RES Directive and socialised across all grid users. This was previously discussed in the NSCOGI Possible Market Arrangements Paper.

Option 3: ORG in its own Bidding Zone

In this option the ORG is placed in its own bidding zone (bidding zone C) separate from both bidding zone A and bidding zone B. The trading arrangements would be as follows:

- Traders in bidding zone A make bids and offers in bidding zone A and traders in bidding zone B make bids and offers in bidding zone B; ORG makes offers into its very own bidding zone, bidding zone C.
- Bids and offers from bidding zone A, bidding zone B and bidding zone C are submitted by local Market Operators to the Shared Order Book. The continuous trading matching algorithm matches bids and offers where there remains sufficient available capacity on the interconnections between bidding zones A, B and C.
- In the example in Figure 4 above, the additional 50MWh from the ORG can flow only to bidding zone A. This is because the interconnection capacity into bidding zone B is already fully utilised from the day ahead stage.
- Therefore this option leads to a largely similar outcome as Option 1 with the possible solutions as set out in Section 1. As argued previously by stakeholders, Option 1 would allow the ORG the flexibility to bid into the lower priced bidding zones (either B or A) as there is likely to be available capacity in that direction following the outcome of day ahead market coupling. However, it could be argued that the ORG could bid into the lower priced bidding zone anyway if they were part of bidding zone A/B by submitting a bid to the pan European shared order book
- In the case where the interconnector is congested in direction B to A, the ORG would no longer have access to offers in Bidding Zone A and therefore this Option may no longer be, strictly speaking, considered Option 1 at intra day stage. However, the ORG could still sell its output into Bidding Zone B.
- This means that there does not appear to be any tangible advantage for an ORG to be located in its own bidding zone at the intra-day stage.

5.6 Stakeholder Views

As discussed in Section 1, several stakeholders see Option 3 as advantageous for the intraday timeframe as it would allow the ORG the flexibility to bid into the lower priced bidding zones as there is likely to be available capacity in that direction following the outcome of day ahead market coupling.

However, EWEA cautioned that this should be balanced with an awareness that different zones in different time frames could lead to perverse incentives for market participants to sell more generation than is planned in the day-ahead market in a high price area and then buy back in the intra-day market in a low price area.

Some stakeholders also suggested that more probabilistic power trading in a future with large amounts of variable renewables should be considered. In this context, for the amount of electricity by an ORG bound to the forecast error (e.g. about 5% of the day-ahead forecast) could be purchased on the financial market. Energy Options could be developed for use with ORGs, but this would require cross zonal capacity to be made available in the intraday timeframe (for example through explicit intraday access).

5.7 NSCOGI Response

We expect that the intraday timeframe will be used as an adjustment market by ORGs, with most of their output being sold at the day ahead stage. With an potential 5% forecast error for offshore wind from day ahead to real time[16], there could be an argument for incorporating this in the capacity allocation process (for example by reducing the ATC by the forecast error and releasing the capacity intraday), so to ensure priority dispatch is respected and to avoid the ORG being discriminated against. However, it is unclear whether capacity reservation for the intraday timeframe would meet the requirements of the CACM Network Code which would seem to require that all unused capacity at the day ahead stage is made available for the market coupling algorithm.

The two options for the intra-day timeframe set out above (namely, ORG in an interconnected onshore national zone or ORG in a zone of its own) allow for ORGs to access available cross border capacity following day ahead market coupling (which would usually mean capacity is available in the opposite direction to the day ahead flow if this is congested). This would indicate that congestion management should be less of an issue than at the day ahead stage. Assuming that capacity is not reserved for the ORG in the intraday timeframe, the only option for the ORG is to sell into the pan European intraday market which will only match the ORG's offer with bids from the lower bidding zone (or from bidding zones beyond this across Europe as long as not congested). Using the day ahead price as a guide, these bids are likely to be lower than those in higher bidding zone, though this may depend on the liquidity of the intraday market in each zone.

Nonetheless, the price received by the ORG in the intraday timeframe seems not to depend on which option is chosen. In the examples above, an ORG operating in a national bidding zone or its own bidding zone would only be able to trade with participants in the lower bidding zone. The capacity management module should

[16] See the following for some estimated of DA forecast error:
http://www.ewea.org/uploads/tx_err/Internal_energy_market.pdf
http://www.trade-wind.eu/fileadmin/documents/publications/D2.2_Estimates_of_forecast_error_for_aggregated_wind_power_Final.pdf

make the same capacity available to the ORG and the shared order book should match its offer to available bids regardless of which bidding zone it is located in.

However, the difference between the options may come down to how intraday congestion charging is implemented. If the ORG is located in its own bidding zone, it may be required to pay a lower congestion charge than if it were located in bidding zone A as it would not be competing with other market participants in the bidding zone. How the enduring intraday target model (including congestion pricing and the possibility of regional auctions) is implemented may determine which of Option 1 or Option 3 is the most efficient.

A further point is that the pan European intraday market is based on continuous trading with no auction or market clearing price for the ORG to bid into. In the continuous model, cross-zonal capacity is allocated on a first come first served basis. So the available capacity might already be allocated to other generators by the time the ORG updates its forecasts. It is, therefore, important that the intraday market is liquid to allow the ORG to trade out its position close to real time and reduce the risk of exposure to volatile prices and/or penal imbalance prices.

5.8 Conclusion

In conclusion, we agree that own bidding zone (Option 3) may be a viable option for the intraday period and therefore should be studied further. However, as explained above, there does not appear to be any difference between Option 1 and Option 3 in terms of how the ORG would trade out variations in its output in the pan-European intraday market. If this is the case, the benefit of having consistent bidding zones across timeframes may mean that Option 1 is preferable to Option 3 for day ahead and intraday.

However under Option 1, in the case where the interconnector is congested in direction B to A, the ORG would no longer have access to offers in Bidding Zone A and therefore this Option may, strictly speaking, no longer be considered Option 1 at the intraday stage. However, the ORG could still sell its output into Bidding Zone B.

Furthermore, the option of allocating capacity for the intraday phase linked to the day ahead forecast error is worth exploring further. In addition, energy options may also warrant further exploration as a means for the ORG to manage the risk of changes between the forecast output day ahead and the intraday timeframe as well as efficiently valuing cross border flexibility.

6. ORG and Forward Capacity Allocation

6.1 Background and NSCOGI Initial Views

In considering long term transmission rights (physical or financial) as a means of allocating cross border capacity rights to ORGs, the Possible Markets Arrangements Paper considered that this would raise a number of issues:

- Exposure of the ORG to a market risk to which radially connected ORG would not be exposed to the same degree, as only an ORG connected to combined infrastructure would depend totally on having IC capacity to sell its generation.

- The length of time 'long-term capacity' is referring to (monthly/yearly/15-year product) and the nature of the capacity rights – i.e. physical or financial transmission rights could also be an important factor.

- A market in cross-border capacities could be a sub-optimal solution as long as competitors (from different countries) remain unevenly subsidised. Moreover, the lack of participants seeking multi-annual allocation rights could lead to an inefficient market

NSCOGI concluded that additional analysis should be undertaken to examine the use of long term transmission rights for ORGs in an integrated offshore network.

The Target Model currently allows for both physical and financial transmission rights at the forward timescale. The Forward Target Model also allows for multiannual products (subject to agreement of the relevant NRAs) on bidding zone borders. The interaction between multiannual PTRs and FTRs and the options set out in this paper and the Possible Market Arrangements paper are a further area of study. We set out some indicative thoughts below in order to provoke further discussion with stakeholders.

6.2 Stakeholder Views

Several stakeholders (EFET, Europex) were of the view that NSCOGI should explore further the issue of allocating long term transmission rights as a means of ORGs access to cross border capacity.

Europex suggested that the own bidding zone options could be combined with financial transmission rights while EWEA noted that the Target Model provides for flexibility at the forward stage and this gives scope for considering new types of products. Overall, Europex considered that Financial Transmission Rights should be considered further for hybrid interconnection and ORG production.

6.3 Types of Transmission Rights under the Target Model

As discussed in the Possible Market Arrangements Paper, we have assumed that the ORG has priority access to the amount of cross border capacity required to produce its day ahead output. Under this scenario, it is assumed that the TSOs would only issue forward transmission rights for any remaining cross border capacity for each timeframe (i.e. NTC – ORG capacity). If this assumption were to be relaxed, we could then examine how long term transmission rights might be used for an ORG access a hybrid asset.

In general, there may be reasons to allocate FTRs instead of physical rights to ORGs, including that:

- FTRs allow separation of physical flows and financial outcomes to guarantee the ORG's revenue and also allow flexibility for the TSO to dispatch flows.
- Allow ORGs to compete for scarce capacity
- Allow ORGs to hedge their risk if they are able to choose to which Member State they sell their electricity.

Different forward hedging products can be offered to hedge the risk associated with trading between different zones separated by congestion. The Target Model provides for three different kinds of transmission risk hedging products. ENSTO-E, in its recent paper on risk hedging instruments provides the following high level descriptions:

Physical Transmission Rights (PTRs) are linked to cross border capacity and managed by TSOs providing the option to transport a certain volume of electricity in a certain period of time between two areas in a specific direction. The use-it-or-sell-it mechanism ensures that not nominated capacities get automatically sold in the day-ahead market.

Financial Transmission Rights (FTRs) are linked to cross border capacity and managed by TSOs or subsidiary entities and can be implemented to directly hedge risk in the day-ahead markets. FTRs as options entitle their holders to receive a financial compensation equal to the positive (if any) market price differential between two areas during a specified time period in a specific direction. FTRs as obligations in contrast also oblige holders to pay for a negative market price differential.

Contracts for Differences (CfDs) are contracts between two parties, where the underlying value is the price difference between two reference prices. Should the price difference be positive, then the buyer will receive money from the seller; should the difference be negative, then the buyer has to pay the difference to the seller.

6.4 Some Initial Views on Transmission Rights

We have not developed our thinking on how these could apply to ORGs connecting to hybrid assets beyond the initial views set out in the Possible Market Arrangements Paper.

To be clear, transmission rights could be sold as for any other interconnector for the capacity of the hybrid asset between the local bidding zone (in Option 1) or the own bidding zone of the ORG (Bidding Zone C in Option 3) and the other Bidding Zone (Bidding Zone B). The issue is whether, under Option 3, financial transmission rights could be allocated or auctioned as a means of hedging the price differential between the ORG's own bidding zone C and Bidding Zone A.

If transmission rights were to be allocated to the ORG, as an alternative to charging for access on the same base as radially connected generation, Option 3 could have the same effect as Option 1, where the ORG is guaranteed access to Bidding Zone A. The allocation of transmission rights would have to be designed in such a way that the ORG is not put in an advantageous position vis-à-vis radially connected generation, for example if it did not produce and yet received the pay out on the FTR, though such a scenario is unlikely to

occur[17]. Other issues that would need to be solved are the pricing and duration of such transmission rights, in order to ensure that the access to its national zone is not a new elements of risk to ORGs connected to a hybrid asset compared to ORGs which are radially connected (for whom the price of access to the price in zone A is not an element of risk).

Below are some considerations that could be the subject of further NSCOGI studies.

- Currently the Electricity Target Model doesn't preclude multiannual transmission rights, but it is generally considered that such rights would at most be of 3 or 4 years duration[18]. This may not be sufficiently long to provide project developers with certainty, meaning that the use of either PTRs or FTRs could be problematic for ORGs in the general case as they could increase risk to ORGs.

- A further issue with allocating long term transmission rights to ORGs is the firmness of such rights. If the interconnector were to be curtailed for a sustained period, the ORG and market participants would be entitled to financial compensation from the asset owner/TSO, possibly capped at the level of congestion income. If multiannual rights of very long duration were to be auctioned, the firmness costs could either mean that joint project is not financeable or consumers are forced to bear an unreasonable level of risk.

- Lastly, when considering the use of such transmission rights, we must take into account the costs already paid for connection by the ORG. For example, if the ORG pays for a connection to zone A, it should not pay additional fees for accessing this zone.

6.5 Conclusions

As concluded in the first Market Arrangements Paper, in the general case, we do not recommend the use of long term transmission rights for providing ORG with access to cross border capacity. However Transmission Rights could be an efficient approach to manage the risk of congestion costs for an ORG located within its own bidding zone (Option 3) and potentially an efficient means of renewables trading across the internal market. This requires further exploration and discussion with stakeholders.

[17] For example, If FTRs were to be allocated to the ORG as a means of accessing Bidding Zone A and the ORG did not generate at all or partially generated, there would be no congestion between bidding zone C and the lower priced bidding zone and so the value of the FTR would be zero

[18] Some stakeholder have advocated allocating very long term transmission rights on interconnectors so as to facilitate pan European renewables trading. One concern with allocating very long term rights (e.g. 20 years) might be that they preclude the access to the IC for a very long time, potentially discouraging new market participants from entering the market and might disproportionally increase firmness costs for the end user.

7. Conclusions and Recommendations

The following are the preliminary conclusions of this second NSCOGI Market Arrangements Paper:

Day Ahead Market

Bidding Zones

- We consider that Option 3 is worth further analysis at the day ahead stage, in particular in terms of how it interacts with congestion revenues and support mechanisms. We agree that changes to bidding zones across timeframes could have unintended consequences, so for this reason Option 3 is kept as a distinct option for all timeframes - day ahead, intra-day and forward.

- We also agree that bidding zone configurations for ORGs could evolve over time and that a potential solution could be to begin with Option 1 or 4 and progress to Option 3 for a cluster of ORGs as the meshed offshore grid develops.

Congestion Management

- Regarding Priority Dispatch and negative prices, throughout the market arrangements work we have assumed that the short run marginal cost of the ORG is lower than the market price in both markets A and B, which is plausible given that the avoidable costs of an increment in wind generation are close to zero. If one of the markets has an oversupply of zero marginal cost energy (i.e. extremely low or negative prices), the conclusions reached would need more analysis. This is an area of future study for NSCOGI.

Congestion Charging

- As per the conclusion reached in the Possible Market Arrangements Paper, the preferred option is that the ORG should be charged for the asset connection in the same way as radially connected ORG. This could mean either that it pays for priority access to the cross border capacity or that it is awarded such access and costs are socialised through tariffs.

- Under the current frameworks, this implies that it would not need to buy interconnection capacities to get access to the bidding zone into which it bids. We are still of the view that ORGs should not be required to purchase transmission rights to access markets. However, we consider that it should not be precluded as an option as it may prove an efficient outcome if agreed by the ORG, the TSO and NRAs.

Intra Day Market

- In conclusion, we agree that own bidding zone (Option 3) may be a viable option for the intraday period and therefore should be used for further study. However, as explained above, there does not appear to be any difference between Option 1 an Option 3 in terms of how the ORG would trade out variations its output in the pan European intraday market. If this is the case, the benefit of having consistent bidding zones across timeframes may mean that Option 1 is preferable to Option 3 for day ahead and intraday.

- However under Option 1, in the case where the interconnector is congested in direction B to A, the ORG would no longer have access to offers in Bidding Zone A and therefore this Option may no longer be, strictly speaking, considered Option 1 at intraday stage. However, the ORG could still sell its output into Bidding Zone B.

- We are also of the view that the option of allocating capacity for the intraday phase linked to the day ahead forecast error is worth exploring further. In addition, energy options may also be a potentially efficient option for the ORG to manage the risk of changes between forecast output the day ahead and intraday timeframe as well as efficiently valuing cross border flexibility.

Forward Capacity Allocation

As concluded in the first Market Arrangements Paper, in the general case, we do not recommend the use of long term transmission rights for providing ORG with access to cross border capacity. However Transmission Rights could be an efficient approach to manage the risk of congestion costs for an ORG located within its own bidding zone (Option 3) and an potentially an efficient means of renewables trading across the internal market. This requires further exploration and discussion with stakeholders.

8. Next Steps

The following issues have not been explored so far in this paper but could form a useful basis for debate with stakeholders for incorporation into the final report:

- The impact of diverse renewable support mechanisms on the market arrangements for ORGs including consideration of the European Commission Guidelines on renewable energy support schemes.

- The issue of negative prices and their impact on the assumptions in this paper.

- Further consideration of allocating transmission rights for ORGs to access transmission capacity between bidding zones.

- Applying the theoretical concepts in the Market Arrangements Papers to specific case studies and considering how the order of development might affect the market arrangements.